INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
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(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

To:	Interested Parties
Date:	August 16, 2022
From:	Jenny Acker, Chief Permits Branch Office of Air Quality
Source Name:	Fulcrum Centerpoint, LLC
Permit Level:	FESOP – New Source Construction (Minor PSD/EO)
Permit Number:	089-44042-00660
Source Location:	6200 Industrial Highway Gary, IN 46406
Type of Action Taken:	Initial Permit

Notice of Decision: Approval - Effective Immediately

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

The final decision is available on the IDEM website at: http://www.in.gov/apps/idem/caats/
To view the document, choose Search Option **by Permit Number**, then enter permit 44042. This search will also provide the application received date, **draft permit** public notice starts and end date, and **final** permit issuance date.

The final decision is also available via IDEM's Virtual File Cabinet (VFC). Please go to: https://www.IN.gov/idem and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

(continues on next page)

If you would like to request a paper copy of the permit document, please contact IDEM's Office of Records Management:

IDEM - Office of Records Management
Indiana Government Center North, Room 1207
100 North Senate Avenue
Indianapolis, IN 46204
Phone: (317) 232-8667
Fax: (317) 233-6647
Email: IDEMFILEROOM@idem.in.gov

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

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Room N103, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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

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Governor

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Commissioner

New Source Construction and Federally Enforceable State Operating Permit OFFICE OF AIR QUALITY

Fulcrum Centerpoint, LLC
6200 Industrial Highway
Gary, Indiana 46406

(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. 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 2-8 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.

Indiana statutes from IC 13 and rules from 326 IAC, quoted 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 FESOP under 326 IAC 2-8.

Operation Permit No.: F089-44042-00660 Master Agency Interest ID: 17817	
Issued by: Brian Williams Brian Willams, Section Chief Permits Branch Office of Air Quality	Issuance Date: August 16, 2022 Expiration Date: August 16, 2027

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-8-3(b)]

The Permittee owns and operates a stationary biorefinery.

Source Address:	6200 Industrial Highway, Gary, Indiana 46406
General Source Phone Number:	(925) 730-0150
SIC Code:	2999 (Products of Petroleum and Coal, Not Elsewhere Classified)
County Location:	Lake
Source Location Status:	Nonattainment for 8-hour ozone standard Attainment for all other criteria pollutants
Source Status:	Federally Enforceable State Operating Permit Program Minor Source, under PSD and Emission Offset Rules Minor Source, Section 112 of the Clean Air Act Not 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-8-3(c)(3)]

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

(a) Three (3) feedstock storage buildings, identified as FDSTG-1, FDSTG-2, and FDSTG-3, approved in 2022 for construction, with a combined maximum capacity of 1,650 tons per day, each using a baghouse for particulate control, and exhausting to stack SV1.

(b) Three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, approved in 2022 for construction, with a maximum throughput of 550 tons per day and a maximum heat input capacity of 30.73 MMBtu/hr, each, equipped with low-NOx burners, each using a baghouse for particulate control, and exhausting to stack SV2.

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:

(1) Three (3) steam reformers, equipped with three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, with a maximum heat input capacity of 75.6 MMBtu/hr, each, using a SCR system for NOx control, and exhausting to stacks SV5, SV6, and SV7;

(2) Three (3) carbon trim cells (CTC);

(3) Three (3) partial oxidation (POx) units;

(4) Three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3; and

Under 40 CFR 60, Subpart Dc, the heat recovery steam generators (HRSGs) are considered affected facilities.

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr, and exhausting to stack SV9.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

Under 40 CFR 60, Subpart RRR, the gasifier trains and related processes are considered affected facilities.

(d) Three (3) ash silos, identified as ASH1, ASH2, and ASH3, approved in 2022 for construction, with a maximum loading rate of 1.0 ton/hr, each, using filters for particulate control, and exhausting to stack SV3.

(e) Three (3) bed media silos, identified as BMS1, BMS2, and BMS3, approved in 2022 for construction, with a maximum loading rate of 0.23 tons per hour, using filters for particulate control, and exhausting to stack SV4.

(f) One (1) sulfur removal unit, identified as SRU, approved in 2022 for construction, with a maximum airflow rate of 27,068 acfm, using an amine-based acid gas removal system to remove hydrogen sulfide and carbon dioxide from syngas, and exhausting to stack SV8.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

(g) One (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, approved in 2022 for construction, converting syngas into FT liquids (syncrude), with a maximum feedstock equivalent capacity of 1,650 tons per day. The FT liquids are thermally separated into a heavy FT liquid stream (HFTL) and a medium FT liquid stream (MFTL). The water generated in the FT process is separated from the MFTL and sent to the wastewater treatment facility. The HFTL and MFTL are sent to the HFTL and MFTL intermediate storage tanks. Unreacted syngas is separated from the MFTL and either recycled back to the FT Reactor, sent to the POx units for methane reforming or combusted in the utility boiler as purge gas. The HFTL and MFTL hydrocarbon streams are sent from the intermediate storage tanks to the syncrude upgrading section.

(h) One (1) utility boiler, identified as BOIL, approved in 2022 for construction, with a maximum heat input capacity of 249.20 MMBtu/hr for natural gas and 36.80 MMBtu/hr for purge gas, using a SCR for NOx control and an oxidation catalyst for VOC and CO control, and exhausting to stack SV10. The utility boiler is equipped with a continuous emission monitoring systems (CEMS) for measuring NOx and O_2 (or CO_2) emissions from the SCR system.

Under the 40 CFR 60, Subpart Db, this is considered an affected facility.

(i) One (1) external floating roof HFTL storage tank, identified as T6, approved in 2022 for construction, with a maximum storage capacity of 73,000 gallons, and exhausting indoors.

(j) One (1) external floating roof MFTL storage tank, identified as T7, approved in 2022 for construction, with a maximum storage capacity of 94,300 gallons, and exhausting indoors.

(k) One (1) syncrude upgrading section, cracking syncrude from the FT synthesis reactor into Synthetic Paraffinic Kerosene (SPK) and naphtha, consisting of the following:

(1) One (1) hydrocracker heater, identified as HYCR, approved in 2022 for construction, with a maximum heat input capacity of 9.70 MMBtu/hr, and exhausting to stack SV11.

(2) One (1) fractionator heater, identified as FRAC, approved in 2022 for construction, with a maximum heat input capacity of 9.70 MMBtu/hr, and exhausting to stack SV12.

(3) One (1) product stripper heater, identified as PSH, approved in 2022 for construction, with a maximum heat input capacity of 3.70 MMBtu/hr, and exhausting to stack SV13.

(l) Three (3) vertical fixed roof product storage tanks, identified as T1, T2, and T3, approved in 2022 for construction, with a maximum storage capacity of 587,000 gallons of SPK, each, and exhausting to vents SV14, SV15, and SV16.

(m) One (1) vertical fixed roof off-spec product storage tank, identified as T4, approved in 2022 for construction, with a maximum storage capacity of 216,000 gallons, and exhausting to vent SV17.

(n) One (1) vertical fixed roof solvent sump drum, identified as T5, approved in 2022 for construction, with a maximum storage capacity of 45,000 gallons, and exhausting to vent SV18.

(o) One (1) evaporative cooling tower, identified as CT, approved in 2022 for construction, with a maximum recirculating capacity of 39,990 gpm, and exhausting to the atmosphere.

(p) One (1) wastewater treatment system, identified as WTS, approved in 2022 for construction, with a nominal capacity of 1,426 lpm, as follows:

(1) One (1) equalization tank to buffer the treatment system against variations in wastewater quality and flow, which flows to the pH adjustment tank.

(2) One (1) pH adjustment tank to raise the pH of the wastewater, which flows to the reaction tank.

(3) One (1) reaction tank to allow for chemical addition of a coagulant (ferric chloride) and organosulfide, which removes heavy metals by converting the soluble metals to an insoluble metal sulfide precipitate. The reaction tank feeds a clarifier, where a polymer is added to increase the particle size of the insoluble particles to allow settling within the clarifier. Suspended solids from the wastewater system would be removed with traditional clarification techniques. Settled solids from clarification would be directed to dewatering equipment.

(4) One (1) neutral tank to adjust the pH of the clarified water with hydrochloric acid to prevent scaling in the downstream filters used to polish the clarifier effluent to achieve low residual solids.

(5) One (1) sludge tank containing sludge produced by the clarifying process, which will be dewatered prior to disposal using plate and frame filter presses. The dewatered solids will be sent to a landfill for disposal and the filtrate collected and recycled back to the front end of the wastewater treatment system.

(q) One (1) truck and railcar loadout system, identified as TRC, approved in 2022 for construction, with a maximum throughput rate of 34,000,000 gallons of synthetic paraffinic kerosene (SPK) per year, using flare LOAD as control, which is supplemented by natural gas, has a maximum heat input capacity of 16.60 MMBtu/hr, equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr, and exhausting through stack SV19.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

A.2 Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-8-3(c)(3)(I)]

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

(a) Vessels storing lubricating oils

(b) Application of grease and lubricants as temporary protective coatings

(c) Replacement or repair of electrostatic precipitators, bags in baghouses and filters in other air filtration equipment

(d) Heat exchanger cleaning and repair

(e) Process vessel degassing and cleaning to prepare for internal repairs

(f) Flue gas conditioning systems and associated chemicals, such as ammonia

(g) Blowdown for utility boilers and cooling towers

(h) Fugitive equipment leak emissions from valves, connectors, and seals

(i) Slag handling activities, approved in 2022 for construction, with a maximum capacity of 1,050 lbs/hr, having no controls, and exhausting to the atmosphere.

(j) One (1) diesel-fired fire pump engine, identified as PUMP, approved in 2022 for construction, with a maximum capacity of 399 hp, and exhausting to stack SV20.

Under 40 CFR 60, Subpart IIII, this is an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is an affected source.

(k) One (1) diesel-fired emergency generator, identified as EG, approved in 2022 for construction, with a maximum capacity of 28.2 MMBtu/hr, and exhausting to stack SV21.

Under 40 CFR 60, Subpart IIII, this is considered an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is considered a new affected source.

(l) Four (4) diesel storage tanks, approved in 2022 for construction, with a combined maximum storage capacity of 4,000 gallons.

(m) Paved roads and parking lots with public access

A.3 FESOP Applicability [326 IAC 2-8-2]

This stationary source, otherwise required to have a Part 70 permit as described in 326 IAC 2-7-2(a), has applied to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) for a Federally Enforceable State Operating Permit (FESOP).

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-8-1]

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

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

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), the Commissioner may revoke this permit if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

B.3 Affidavit of Construction [326 IAC 2-5.1-3(h)] [326 IAC 2-5.1-4][326 IAC 2-8]

This document shall also become the approval to operate pursuant to 326 IAC 2-5.1-4 and 326 IAC 2-8 when prior to the start of operation, the following requirements are met:

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

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

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

B.4 Permit Term [326 IAC 2-8-4(2)][326 IAC 2-1.1-9.5][IC 13-15-3-6(a)]

(a) This permit, F089-44042-00660, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

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

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

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

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

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

B.6 Enforceability [326 IAC 2-8-6] [IC 13-17-12]

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

B.7 Severability [326 IAC 2-8-4(4)]

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

B.8 Property Rights or Exclusive Privilege [326 IAC 2-8-4(5)(D)]

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

B.9 Duty to Provide Information [326 IAC 2-8-4(5)(E)]

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

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

B.10 Certification [326 IAC 2-8-3(d)][326 IAC 2-8-4(3)(C)(i)][326 IAC 2-8-5(1)]

(a) A certification required by this permit meets the requirements of 326 IAC 2-8-5(a)(1) if:

(1) it contains a certification by an "authorized individual" as defined by 326 IAC 2-1.1-1(1), 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) An "authorized individual" is defined at 326 IAC 2-1.1-1(1).

B.11 Annual Compliance Certification [326 IAC 2-8-5(a)(1)]

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

(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 2-8-4(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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

B.12 Compliance Order Issuance [326 IAC 2-8-5(b)]

IDEM, OAQ may issue a compliance order to this Permittee upon discovery that this permit is in nonconformance with an applicable requirement. The order may require immediate compliance or contain a schedule for expeditious compliance with the applicable requirement.

B.13 Preventive Maintenance Plan [326 IAC 1-6-3][326 IAC 2-8-4(9)]

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

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

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

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

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

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

The Permittee shall implement the PMPs.

(b) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

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

B.14 Emergency Provisions [326 IAC 2-8-12]

(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 except as provided in 326 IAC 2-8-12.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a health-based or 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 2-8-4(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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(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 2-8-3(c)(6) 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 2-8 and any other applicable rules.

(g) Operations may continue during an emergency only if the following conditions are met:

(1) 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.

(2) If an emergency situation causes a deviation from a health-based limit, the Permittee may not continue to operate the affected emissions facilities unless:

(A) The Permittee immediately takes all reasonable steps to correct the emergency situation and to minimize emissions; and

(B) Continued operation of the facilities is necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw material of substantial economic value.

Any operations shall continue no longer than the minimum time required to prevent the situations identified in (g)(2)(B) of this condition.

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

(a) All terms and conditions of permits established prior to F089-44042-00660 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised, or

(3) deleted.

(b) All previous registrations and permits are superseded by this permit.

B.16 Termination of Right to Operate [326 IAC 2-8-9][326 IAC 2-8-3(h)]

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 2-8-3(h) and 326 IAC 2-8-9.

B.17 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-8-4(5)(C)][326 IAC 2-8-7(a)][326 IAC 2-8-8]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Federally Enforceable State 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 2-8-4(5)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(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 2-8-8(a)]

(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 2-8-8(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-8-8(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 2-8-8(c)]

B.18 Permit Renewal [326 IAC 2-8-3(h)]

(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 2-8-3. 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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

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 2-8 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 2-8-3(g), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.19 Permit Amendment or Revision [326 IAC 2-8-10][326 IAC 2-8-11.1]

(a) Permit amendments and revisions are governed by the requirements of 326 IAC 2-8-10 or 326 IAC 2-8-11.1 whenever the Permittee seeks to amend or modify this permit.

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

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

Any such application does require a certification that meets the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-8-10(b)(3)]

B.20 Operational Flexibility [326 IAC 2-8-15][326 IAC 2-8-11.1]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-8-15(b) and (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 approval required by 326 IAC 2-8-11.1 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 5
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 2-8-15(b)(1) and (c). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-8-15(b)(1) and (c).

(b) Emission Trades [326 IAC 2-8-15(b)]
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 2-8-15(b).

(c) Alternative Operating Scenarios [326 IAC 2-8-15(c)]
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 2-8-4(7). No prior notification of IDEM, OAQ or U.S. EPA is required.

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

B.21 Source Modification Requirement [326 IAC 2-8-11.1]

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

B.22 Inspection and Entry [326 IAC 2-8-5(a)(2)][IC 13-14-2-2][IC 13-17-3-2][IC 13-30-3-1]

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 FESOP 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, at reasonable times, 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, at reasonable times, 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, at reasonable times, 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.23 Transfer of Ownership or Operational Control [326 IAC 2-8-10]

(a) The Permittee must comply with the requirements of 326 IAC 2-8-10 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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-8-10(b)(3)]

B.24 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-8-4(6)] [326 IAC 2-8-16][326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ no later than 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) 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 317-233-8590 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.25 Credible Evidence [326 IAC 2-8-4(3)][326 IAC 2-8-5][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 2-8-4(1)]

C.1 Overall Source Limit [326 IAC 2-8]

The purpose of this permit is to limit this source's potential to emit to less than major source levels for the purpose of Section 502(a) of the Clean Air Act.

(a) Pursuant to 326 IAC 2-8:

(1) The potential to emit volatile organic compounds (VOCs) from the entire source shall be limited to less than fifty (50) tons per twelve (12) consecutive month period;

(2) The potential to emit nitrogen oxides (NOx) from the entire source shall be limited to less than fifty (50) tons per twelve (12) consecutive month period;

(3) The potential to emit any regulated pollutant, except particulate matter (PM), volatile organic compounds (VOCs), and nitrogen oxides (NOx), from the entire source shall be limited to less than one hundred (100) tons per twelve (12) consecutive month period;

(4) The potential to emit any individual hazardous air pollutant (HAP) from the entire source shall be limited to less than ten (10) tons per twelve (12) consecutive month period; and

(5) The potential to emit any combination of HAPs from the entire source shall be limited to less than twenty-five (25) tons per twelve (12) consecutive month period.

(b) Pursuant to 326 IAC 2-2 (PSD), potential to emit particulate matter (PM) from the entire source shall be limited to less than two hundred fifty (250) tons per twelve (12) consecutive month period.

(c) This condition shall include all emission points at this source including those that are insignificant as defined in 326 IAC 2-7-1(21). The source shall be allowed to add insignificant activities not already listed in this permit, provided the source's potential to emit does not exceed the above specified limits.

(d) Section D of this permit contains independently enforceable provisions to satisfy this requirement.

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 twenty percent (20%) 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).

C.6 Fugitive Particulate Matter Emissions [326 IAC 6.8-10-3]

Pursuant to 326 IAC 6.8-10-3 (formerly 326 IAC 6-1-11.1) (Lake County Fugitive Particulate Matter Control Requirements), the particulate matter emissions from source wide activities shall meet the following requirements:

(a) The average instantaneous opacity of fugitive particulate emissions from a paved road shall not exceed ten percent (10%).

(b) The average instantaneous opacity of fugitive particulate emissions from an unpaved road shall not exceed ten percent (10%).

(c) The opacity of fugitive particulate emissions from exposed areas shall not exceed ten percent (10%) on a six (6) minute average.

(d) The opacity of fugitive particulate emissions from continuous transfer of material onto and out of storage piles shall not exceed ten percent (10%) on a three (3) minute average.

(e) The opacity of fugitive particulate emissions from storage piles shall not exceed ten percent (10%) on a six (6) minute average.

(f) There shall be a zero (0) percent frequency of visible emission observations of a material during the inplant transportation of material by truck or rail at any time.

(g) The opacity of fugitive particulate emissions from the inplant transportation of material by front end loaders and skip hoists shall not exceed ten percent (10%).

(h) Material processing facilities shall include the following:

(1) There shall be a zero (0) percent frequency of visible emission observations from a building enclosing all or part of the material processing equipment, except from a vent in the building.

(2) The PM10 emissions from building vents shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(3) The PM10 stack emissions from a material processing facility shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(4) The opacity of fugitive particulate emissions from the material processing facilities, except a crusher at which a capture system is not used, shall not exceed ten percent (10%) opacity.

(5) The opacity of fugitive particulate emissions from a crusher at which a capture system is not used shall not exceed fifteen percent (15%).

(i) The opacity of particulate emissions from dust handling equipment shall not exceed ten percent (10%).

(j) Material transfer limits shall be as follows:

(1) The average instantaneous opacity of fugitive particulate emissions from batch transfer shall not exceed ten percent (10%).

(2) Where adequate wetting of the material for fugitive particulate emissions control is prohibitive to further processing or reuse of the material, the opacity shall not exceed ten percent (10%), three (3) minute average.

(3) Slag and kish handling activities at integrated iron and steel plants shall comply with the following particulate emissions limits:

(A) The opacity of fugitive particulate emissions from transfer from pots and trucks into pits shall not exceed twenty percent (20%) on a six (6) minute average.

(B) The opacity of fugitive particulate emissions from transfer from pits into front end loaders and from transfer from front end loaders into trucks shall comply with the fugitive particulate emission limits in 326 IAC 6.8-10-3(9).

(k) Any facility or operation not specified in 326 IAC 6.8-10-3 shall meet a twenty percent (20%), three (3) minute average opacity standard.

The Permittee shall achieve these limits by controlling fugitive particulate matter emissions according to the Fugitive Dust Control Plan (included as Attachment A to the operating permit).

C.7 Lake County Particulate Matter Contingency Measures [326 IAC 6.8-11]

The Permittee shall comply with the applicable provisions of 326 IAC 6.8-11 (Lake County Particulate Matter Contingency Measures).

C.8 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.

C.9 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(c).

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

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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(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.

Testing Requirements [326 IAC 2-8-4(3)]

C.10 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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(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.11 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 2-8-4(1)][326 IAC 2-8-5(a)(1)]

C.12 Compliance Monitoring [326 IAC 2-8-4(3)][326 IAC 2-8-5(a)(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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

C.13 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-8-4(3)][326 IAC 2-8-5(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 2-8-4][326 IAC 2-8-5(a)(1)]

C.14 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.15 Risk Management Plan [326 IAC 2-8-4] [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.16 Response to Excursions or Exceedances [326 IAC 2-8-4] [326 IAC 2-8-5]

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

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

C.17 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-8-4][326 IAC 2-8-5]

(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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

Record Keeping and Reporting Requirements [326 IAC 2-8-4(3)]

C.18 Emission Statement [326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit an emission statement by July 1 following a calendar year when the source emits oxides of nitrogen or volatile organic compounds into the ambient air equal to or greater than twenty-five (25) tons. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

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 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

C.19 General Record Keeping Requirements [326 IAC 2-8-4(3)] [326 IAC 2-8-5]

(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 FESOP.

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.20 General Reporting Requirements [326 IAC 2-8-4(3)(C)] [326 IAC 2-1.1-11]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1). 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) The first report shall cover the period commencing on the date of issuance of this permit or the date of initial start-up, whichever is later, and ending on the last day of the reporting period. Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit, "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

Stratospheric Ozone Protection

C.21 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) Three (3) feedstock storage buildings, identified as FDSTG-1, FDSTG-2, and FDSTG-3, approved in 2022 for construction, with a combined maximum capacity of 1,650 tons per day, each using a baghouse for particulate control, and exhausting to stack SV1.

(b) Three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, approved in 2022 for construction, with a maximum throughput of 550 tons per day and a maximum heat input capacity of 30.73 MMBtu/hr, each, equipped with low-NOx burners, each using a baghouse for particulate control, and exhausting to stack SV2.

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:

(1) Three (3) steam reformers, equipped with three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, with a maximum heat input capacity of 75.6 MMBtu/hr, each, using a SCR system for NOx control, and exhausting to stacks SV5, SV6, and SV7;

(2) Three (3) carbon trim cells (CTC);

(3) Three (3) partial oxidation (POx) units;

(4) Three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3; and

Under 40 CFR 60, Subpart Dc, the heat recovery steam generators (HRSGs) are considered affected facilities.

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr, and exhausting to stack SV9.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

Under 40 CFR 60, Subpart RRR, the gasifier trains and related processes are considered affected facilities.

(d) Three (3) ash silos, identified as ASH1, ASH2, and ASH3, approved in 2022 for construction, with a maximum loading rate of 1.0 ton/hr, each, using filters for particulate control, and exhausting to stack SV3.

(e) Three (3) bed media silos, identified as BMS1, BMS2, and BMS3, approved in 2022 for construction, with a maximum loading rate of 0.23 tons per hour, using filters for particulate control, and exhausting to stack SV4.

(f) One (1) sulfur removal unit, identified as SRU, approved in 2022 for construction, with a maximum airflow rate of 27,068 acfm, using an amine-based acid gas removal system to remove hydrogen sulfide and carbon dioxide from syngas, and exhausting to stack SV8.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

(g) One (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, approved in 2022 for construction, converting syngas into FT liquids (syncrude), with a maximum feedstock equivalent capacity of 1,650 tons per day. The FT liquids are thermally separated into a heavy FT liquid stream (HFTL) and a medium FT liquid stream (MFTL). The water generated in the FT process is separated from the MFTL and sent to the wastewater treatment facility. The HFTL and MFTL are sent to the HFTL and MFTL intermediate storage tanks. Unreacted syngas is separated from the MFTL and either recycled back to the FT Reactor, sent to the POx units for methane reforming or combusted in the utility boiler as purge gas. The HFTL and MFTL hydrocarbon streams are sent from the intermediate storage tanks to the syncrude upgrading section.

(h) One (1) utility boiler, identified as BOIL, approved in 2022 for construction, with a maximum heat input capacity of 249.20 MMBtu/hr for natural gas and 36.80 MMBtu/hr for purge gas, using a SCR for NOx control and an oxidation catalyst for VOC and CO control, and exhausting to stack SV10. The utility boiler is equipped with a continuous emission monitoring systems (CEMS) for measuring NOx and O_2 (or CO_2) emissions from the SCR system.

Under the 40 CFR 60, Subpart Db, this is considered an affected facility.

(i) One (1) external floating roof HFTL storage tank, identified as T6, approved in 2022 for construction, with a maximum storage capacity of 73,000 gallons, and exhausting indoors.

(j) One (1) external floating roof MFTL storage tank, identified as T7, approved in 2022 for construction, with a maximum storage capacity of 94,300 gallons, and exhausting indoors.

(k) One (1) syncrude upgrading section, cracking syncrude from the FT synthesis reactor into Synthetic Paraffinic Kerosene (SPK) and naphtha, consisting of the following:

(1) One (1) hydrocracker heater, identified as HYCR, approved in 2022 for construction, with a maximum heat input capacity of 9.70 MMBtu/hr, and exhausting to stack SV11.

(2) One (1) fractionator heater, identified as FRAC, approved in 2022 for construction, with a maximum heat input capacity of 9.70 MMBtu/hr, and exhausting to stack SV12.

(3) One (1) product stripper heater, identified as PSH, approved in 2022 for construction, with a maximum heat input capacity of 3.70 MMBtu/hr, and exhausting to stack SV13.

(l) Three (3) vertical fixed roof product storage tanks, identified as T1, T2, and T3, approved in 2022 for construction, with a maximum storage capacity of 587,000 gallons of SPK, each, and exhausting to vents SV14, SV15, and SV16.

(m) One (1) vertical fixed roof off-spec product storage tank, identified as T4, approved in 2022 for construction, with a maximum storage capacity of 216,000 gallons, and exhausting to vent SV17.

(n) One (1) vertical fixed roof solvent sump drum, identified as T5, approved in 2022 for construction, with a maximum storage capacity of 45,000 gallons, and exhausting to vent SV18.

(o) One (1) evaporative cooling tower, identified as CT, approved in 2022 for construction, with a maximum recirculating capacity of 39,990 gpm, and exhausting to the atmosphere.

(p) One (1) wastewater treatment system, identified as WTS, approved in 2022 for construction, with a nominal capacity of 1,426 lpm, as follows:

(1) One (1) equalization tank to buffer the treatment system against variations in wastewater quality and flow, which flows to the pH adjustment tank.

(2) One (1) pH adjustment tank to raise the pH of the wastewater, which flows to the reaction tank.

(3) One (1) reaction tank to allow for chemical addition of a coagulant (ferric chloride) and organosulfide, which removes heavy metals by converting the soluble metals to an insoluble metal sulfide precipitate. The reaction tank feeds a clarifier, where a polymer is added to increase the particle size of the insoluble particles to allow settling within the clarifier. Suspended solids from the wastewater system would be removed with traditional clarification techniques. Settled solids from clarification would be directed to dewatering equipment.

(4) One (1) neutral tank to adjust the pH of the clarified water with hydrochloric acid to prevent scaling in the downstream filters used to polish the clarifier effluent to achieve low residual solids.

(5) One (1) sludge tank containing sludge produced by the clarifying process, which will be dewatered prior to disposal using plate and frame filter presses. The dewatered solids will be sent to a landfill for disposal and the filtrate collected and recycled back to the front end of the wastewater treatment system.

(q) One (1) truck and railcar loadout system, identified as TRC, approved in 2022 for construction, with a maximum throughput rate of 34,000,000 gallons of synthetic paraffinic kerosene (SPK) per year, using flare LOAD as control, which is supplemented by natural gas, has a maximum heat input capacity of 16.60 MMBtu/hr, equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr, and exhausting through stack SV19.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

Insignificant Activities:

(j) One (1) diesel-fired fire pump engine, identified as PUMP, approved in 2022 for construction, with a maximum capacity of 399 hp, and exhausting to stack SV20.

Under 40 CFR 60, Subpart IIII, this is an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is an affected source.

(k) One (1) diesel-fired emergency generator, identified as EG, approved in 2022 for construction, with a maximum capacity of 28.2 MMBtu/hr, and exhausting to stack SV21.

Under 40 CFR 60, Subpart IIII, this is considered an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is considered a new affected source.

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

Emission Limitations and Standards [326 IAC 2-8-4(1)]

D.1.1 PSD Minor Limits for PM [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable, the Permittee shall comply with the following:

(a) PM emissions from the units named in the table below shall not exceed the values shown in the table:

Unit Description	Control Device	PM Emission Limit (lbs/hr)
Feedstock Storage Building (FDSTG-1)	Baghouse	12.86
Feedstock Storage Building (FDSTG-2)	Baghouse	12.86
Feedstock Storage Building (FDSTG-3)	Baghouse	12.86
Feedstock Dryer (DRYER-1)	Baghouse	1.20
Feedstock Dryer (DRYER-2)	Baghouse	1.20
Feedstock Dryer (DRYER-3)	Baghouse	1.20
Ash Silo (ASH1)	Filter	0.055
Ash Silo (ASH2)	Filter	0.055
Ash Silo (ASH3)	Filter	0.055
Bed Media Silo (BMS1)	Filter	0.055
Bed Media Silo (BMS2)	Filter	0.055
Bed Media Silo (BMS3)	Filter	0.055

Compliance with these limits, combined with the potential to emit PM from all other emission units at this source, shall limit the source-wide total potential to emit of PM to less than 250 tons per twelve (12) consecutive month period and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable.

D.1.2 FESOP, PSD, and Emission Offset Limits [326 IAC 2-8-4] [326 IAC 2-2] [326 IAC 2-3]

Pursuant to 326 IAC 2-8-4 (FESOP), and in order to render the requirements of 326 IAC 2-7 (Part 70 Permits), 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), not applicable, the Permittee shall comply with the following:

(a) PM10 and PM2.5 emissions from the units named in the table below shall not exceed the values shown in the table:

Unit Description	Control Device	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
Feedstock Storage Building (FDSTG-1)	Baghouse	2.83	1.42
Feedstock Storage Building (FDSTG-2)	Baghouse	2.83	1.42
Feedstock Storage Building (FDSTG-3)	Baghouse	2.83	1.42
Feedstock Dryer (DRYER-1)	Baghouse	1.20	1.20

Unit Description	Control Device	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
Feedstock Dryer (DRYER-2)	Baghouse	1.20	1.20
Feedstock Dryer (DRYER-3)	Baghouse	1.20	1.20
Ash Silo (ASH1)	Filter	0.055	0.055
Ash Silo (ASH2)	Filter	0.055	0.055
Ash Silo (ASH3)	Filter	0.055	0.055
Bed Media Silo (BMS1)	Filter	0.055	0.055
Bed Media Silo (BMS2)	Filter	0.055	0.055
Bed Media Silo (BMS3)	Filter	0.055	0.055

(b) The emergency generator shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) NOx emissions from the emergency generator shall not exceed 0.024 pounds per horsepower hour.

(d) VOC emissions from the emergency generator shall not exceed 0.000705 pounds per horsepower hour.

(e) The fire pump engine shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

(f) NOx emissions from the fire pump engine shall not exceed 0.031 pounds per horsepower hour.

(g) VOC emissions from the fire pump engine shall not exceed 0.0025 pounds per horsepower hour.

(h) Total NOx emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater shall not exceed 41.91 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

(i) Total VOC emissions from FT Reactor, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks shall not exceed 48.12 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

(j) Total CO emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater shall not exceed 83.69 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

Compliance with these limits, combined with the potential to emit PM10, PM2.5, NOx, VOC, and CO from all other emission units at this source, shall limit the source-wide total potential to emit of PM10, PM2.5, and CO to less than 100 tons per twelve (12) consecutive month period, each, and NOx and VOC to less than 50 tons per twelve (12) consecutive month period, each, and shall

render the requirements of 326 IAC 2-7 (Part 70 Permits), 326 IAC (Prevention of Significant Deterioration (PSD)), and 326 IAC 2-3 (Emission Offset) not applicable.

D.1.3 VOC Best Available Control Technology (BACT) [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (VOC BACT), the Permittee shall comply with the following:

(a) The VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor shall be controlled by the utility boiler (BOIL) except when flaring the VOC emissions during startup and shutdown. The terms startup and shutdown are defined as follows:

(1) Startup means the setting into operation of the gasifier trains (GT-1, GT-2, and/or GT-3) and/or the FT Reactor, when syngas is being ducted to the flare.

(2) Shutdown means cessation of operation of the gasifier trains (GT-1, GT-2, and/or GT-3) and/or the FT Reactor, when syngas is being ducted to the flare, or the period when gas is being ducted to the flare during draining and inspection of storage tanks.

(b) The utility boiler (BOIL) shall operate with an overall VOC control efficiency (including the capture efficiency and destruction efficiency) of not less than 98.0% or the VOC outlet concentration shall not exceed 10 ppmvd of VOC at 100% capture.

(c) VOC emissions from the utility boiler stack (SV10) shall not exceed 1.23 lb/hr.

D.1.4 Particulate Emission Limitations for Lake County [326 IAC 6.8-1-2]

(a) Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the three (3) feedstock storage buildings, identified as FDSTG-1, FDSTG-2, and FDSTG-3, the three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, the three (3) ash silos, identified as ASH1, ASH2, and ASH3, the three (3) bed media silos, identified as BMS1, BMS2, and BMS3, the one (1) evaporative cooling tower, identified as CT, three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, the one (1) loadout flare, identified as LOAD, the one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot (dscf)), each.

(b) Pursuant to 326 IAC 6.8-1-2(b)(3), particulate matter emissions from the one (1) utility boiler, identified as BOIL, shall not exceed one-hundredth (0.01) grain per dry standard cubic foot (dscf).

D.1.5 Preventive Maintenance Plan [326 IAC 2-8-4(9)]

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

Compliance Determination Requirements [326 IAC 2-8-4(1)]

D.1.6 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a), not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on the feedstock storage buildings, each controlled by one (1) baghouse, exhausting to stack SV1, utilizing methods as approved by the Commissioner, at least

once every five (5) years from the most recent valid compliance demonstration. PM10 and PM2.5 include filterable and condensable particulate matter.

(b) In order to demonstrate compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a) not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on the feedstock dryers, each controlled by one (1) baghouse exhausting to stack SV2, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration. PM10 and PM2.5 include filterable and condensable particulate matter.

(c) In order to demonstrate compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a) not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on the ash silos, each controlled by one (1) filter exhausting to stack SV3, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration. PM10 and PM2.5 include filterable and condensable particulate matter.

(d) In order to demonstrate compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a) not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on the bed media silos, each controlled by one (1) filter exhausting to stack SV4, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration. PM10 and PM2.5 include filterable and condensable particulate matter.

(e) In order to demonstrate compliance with Condition D.1.2(h), not later than 180 days after initial start-up, the Permittee shall perform uncontrolled NOx testing on the feedstock dryers, exhausting to stack SV2, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(f) In order to demonstrate compliance with Condition D.1.2(h), not later than 180 days after initial start-up, the Permittee shall perform NOx testing on the pulse combustors, each controlled by one (1) SCR system, exhausting to stacks SV5, SV6, and SV7, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(g) In order to demonstrate compliance with Condition D.1.2(i), not later than 180 days after initial start-up, the Permittee shall perform VOC (including emission rate and overall control efficiency) testing on the pulse combustors, exhausting to stacks SV5, SV6, and SV7, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(h) In order to demonstrate compliance with Condition D.1.2(i), and D.1.3 not later than 180 days after initial start-up, the Permittee shall perform VOC (including emission rate and overall control efficiency) testing on the utility boiler, controlled by one (1) oxidation catalyst, exhausting to stack SV10, while combusting natural gas and purge gas from the FT Reactor, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(i) In order to demonstrate compliance with Condition D.1.2(j) not later than 180 days after initial start-up, the Permittee shall perform CO testing on the utility boiler, controlled by one (1) oxidation catalyst, exhausting to stack SV10 utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(j) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.1.7 Volatile Organic Compounds (VOC) - Wastewater

In order to determine compliance with Condition D.1.2(i), the VOC concentration of wastewater samples taken from the wastewater treatment system shall be determined once per week by using one (1) of the test methods specified in 326 IAC 8-20-7(6). Wastewater flow rate measurements shall be taken once per week at the same time as the wastewater VOC concentration measurements.

D.1.8 Volatile Organic Compounds (VOC) - Storage Tanks

In order to demonstrate compliance with Condition D.1.2(i), the Permittee shall determine the VOC emissions of each storage tank in accordance with Section 7.1.3.1 – Routine Losses From Fixed Roof Tanks, Section 7.1.3.2 – Routine Losses From Floating Roof Tanks, and Section 7.1.3.4 – Tank Cleaning Emissions (ref: Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42, 5th Edition, U.S. EPA OAQPS, June 2020) or subsequent editions of the references for those AP-42 sections; Evaporative Loss from Fixed-roof Tanks, Manual of Petroleum Measurement Standards, Chapter 19.1, Fifth Edition, American Petroleum Institute, Washington, D.C., June 2017 and Evaporative Loss from Storage Tank Floating Roof Landings, Manual of Petroleum Measurement Standards, Chapter 19.6, Part 1, First Edition, American Petroleum Institute, Washington, D.C., February 2017; or Evaporative Loss from the Cleaning of Storage Tanks, Technical Report 2568, American Petroleum Institute, Washington, D.C., November 2007.

D.1.9 NOx, VOC, and CO Emission Calculations

Compliance with Conditions D.1.2(h), D.1.2(i), and D.1.2(j) shall be determined by calculating the NOx, VOC, and CO emissions for each month using the following equations:

(a) NOx Emissions:

$$NOx\left(\frac{tons}{month}\right) = \frac{FD(Ef_{FD}) + PC(Ef_{PC}) + B(Ef_B) + F(Ef_{FP}) + FSUSD(Ef_{FSUSD}) + H(Ef_H)}{2{,}000\ lbs/ton}$$

Where:
FD = Feedstock dryers natural gas heat input (MMBtu/month)
Ef_{FD} = 0.030 lb of NOx per MMBtu or the NOx emission rate determined in the most recent stack test (lb/MMBtu)
PC = Pulse combustors natural gas heat input (MMBtu/month)
Ef_{PC} = 0.0089 lb of NOx per MMBtu or the NOx emission rate determined in the most recent stack test (lb/MMBtu)
B = Utility boiler combined natural gas and purge gas heat input (MMBtu/month)
Ef_B = 0.0061 lb of NOx per MMBtu until the CEMS required by Condition D.1.14 begins operation. Then NOx emissions from the utility boiler shall be determined for the month being reported from the CEMS, lb/month.
F = Flare (FLA) Pilot natural gas usage (MMScf/month)
Ef_{FP} = 100 lb of NOx per MMscf
FSUSD = Flare (FLA) heat input from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during startup and shutdown (MMBtu/month)
Ef_{FSUSD} = 0.068 lb of NOx per MMBtu
H = Hydrocracker, Fractionator, and Product Stripper combined natural gas usage (MMscf/month)
Ef_H = 100.00 lb of NOx per MMscf of natural gas

(b) VOC Emissions:

$$VOC\left(\frac{tons}{month}\right) = \frac{FD(Ef_{FD}) + PC(Ef_{PC}) + B(Ef_B) + F(Ef_{FP}) + FSUSD(Ef_{FSUSD}) + H(Ef_H) + ST + (WT\ x\ WT_{VOC}\ x\ f_e)}{2{,}000\ lbs/ton}$$

Where:
FD = Feedstock dryers natural gas heat input (MMscf/month)
Ef_{FD} = 5.5 lb of VOC per MMscf
PC = Pulse combustors natural gas heat input (MMBtu/month)
Ef_{PC} = 0.00556 lb of VOC per MMBtu or the VOC emission rate determined in the most recent stack test (lb/MMBtu)
B = Utility boiler combined natural gas and purge gas heat input (MMBtu/month)
Ef_B = 0.00016 lb of VOC per MMBtu or the VOC emission rate determined in the most recent stack test (lb//MMBtu)
F = Flare (FLA) Pilot natural gas usage (MMScf/month)
Ef_{FP} = 5.5 lb of VOC per MMscf
FSUSD = Flare (FLA) heat input from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during startup and shutdown (MMBtu/month)
Ef_{FSUSD} = 0.14 lb of VOC per MMBtu
H = Hydrocracker, Fractionator, and Product Stripper combined natural gas usage (MMscf/month)
Ef_H = 5.5 lb of VOC per MMscf of natural gas
ST = monthly VOC emissions from storage tanks (lb/month)
WT = Wastewater flow (gallons per month)
WT_{VOC} = VOC concentration (0.00027 lb/gal or the VOC content determined in the most recent sampling)
f_e = 0.683 (weighted average value from EPA 453 D-93-056)

(c) CO Emissions:

$$CO\left(\frac{tons}{month}\right) = \frac{FD(Ef_{FD}) + PC(Ef_{PC}) + B(Ef_B) + F(Ef_{FP}) + FSUSD(Ef_{FSUSD}) + H(Ef_H)}{2{,}000\ lbs/ton}$$

Where:
FD = Feedstock dryers natural gas heat input (MMBtu/month)
Ef_{FD} = 0.037 lb of CO per MMBtu or the CO emission rate determined in the most recent stack test (lb/MMBtu)
PC = Pulse combustors natural gas heat input (MMBtu/month)
Ef_{PC} = 0.041 lb of CO per MMBtu or the CO emission rate determined in the most recent stack test (lb/MMBtu)
B = Utility boiler combined natural gas and purge gas heat input (MMBtu/month)
Ef_B = 0.0037 lb of CO per MMBtu or the CO emission rate determined in the most recent stack test (lb//MMBtu)
F = Flare (FLA) Pilot natural gas usage (MMScf/month)
Ef_{FP} = 84.0 lb of CO per MMscf
FSUSD = Flare (FLA) heat input from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during startup and shutdown (MMBtu/month)
Ef_{FSUSD} = 0.31 lb of CO per MMBtu
H = Hydrocracker, Fractionator, and Product Stripper combined natural gas usage (MMscf/month)
Ef_H = 84.0 lb of CO per MMscf of natural gas

D.1.10 Particulate Control

(a) In order to assure compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a), each of the baghouses for particulate control shall be in operation and control emissions from the respective feedstock storage buildings (FDSTG-1, FDSTG-2, and FDSTG-3) at all times the feedstock storage buildings are in operation.

(b) In order to assure compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a), each of the baghouses for particulate control shall be in operation and control emissions from the respective feedstock dryers (DRYER-1, DRYER-2, and DRYER-3) at all times the feedstock dryers are in operation.

(c) In order to assure compliance with Condition D.1.1(a), D.1.2(a), and D.1.4(a), each of the filters for particulate control shall be in operation and control emissions from the respective ash silos (ASH1, ASH2, and ASH3) and bed media silos (BMS1, BMS2, and BMS3) at all times the ash silos and bed media silos are in operation.

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

D.1.11 NOx Control

In order to assure compliance with Condition D.1.2(h), each of the selective catalytic reduction (SCR) systems for NOx control shall be in operation and control emissions from the respective pulse combustors and utility boiler at all times the pulse combustors and utility boiler are in operation.

D.1.12 VOC Control

(a) In order to assure compliance with Condition D.1.2(i), the oxidation catalyst for VOC control shall be in operation and control emissions from the utility boiler at all times the utility boiler is in operation.

(b) In order to assure compliance with Conditions D.1.2(i), and D.1.3, the utility boiler for purge gas VOC control shall be in operation and control emissions from the FT Reactor at all times the FT Reactor is in operation, except during periods of startup and shutdown.

(c) In order to assure compliance with Condition D.1.2(i), the flare (FLA) for VOC control shall be in operation and control emissions from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during periods of startup and shutdown.

D.1.13 CO Control

In order to assure compliance with Condition D.1.2(j), the oxidation catalyst for CO control shall be in operation and control emissions from the utility boiler at all times the utility boiler is in operation.

D.1.14 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5] [326 IAC 2-8-5(a)(1),(4)] [40 CFR 60, Subpart Db]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems (CEMS) for the utility boiler shall be calibrated, maintained, and operated for measuring NOx and O_2 (or CO_2) emissions from the SCR system, which meet all applicable performance specifications of 326 IAC 3-5.

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a CEMS pursuant to 326 IAC 3-5 and 40 CFR 60.

D.1.15 HAPs - Purge Gas Sampling and Analysis

(a) The Permittee shall sample and analyze the purge gas stream from the FT Reactor for HAP content once per week.

(b) The instrument used for determining the HAP content shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

Compliance Monitoring Requirements [326 IAC 2-8-4(1)][326 IAC 2-8-5(a)(1)]

D.1.16 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) Monitoring of the SCR operating parameters for ammonia flow rate and inlet duct temperature, shall be implemented. The parameters are as follows:

(A) The Permittee shall record the ammonia flow rate and inlet duct temperature at least four (4) times per hour until the primary CEM or a backup CEM is brought online and functioning properly. The Preventive Maintenance Plan for the SCR shall contain troubleshooting contingency and corrective actions for when the readings are outside of the normal range for any one reading during downtime of the NOx CEMS. When for any one reading, the ammonia flow rate and inlet duct temperature are outside the normal range during downtime of the NOx CEMS, the Permittee shall take reasonable response steps. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(B) The instrument used for determining the ammonia flow rate and inlet duct temperature shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time.

D.1.17 Selective Catalytic Reduction System Monitoring Requirements - Pulse Combustors

(a) Pressure drop:
The Permittee shall record the pressure drop across the three (3) selective catalytic reduction systems, used in conjunction with the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, at least once per day when any of the

three (3) pulse combustors are in operation. When for any one reading, the pressure drop across one of the three (3) selective catalytic reduction system, is outside the normal range the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 6.0 and 14.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit.

The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

(b) Temperature:

(i) A continuous monitoring system shall be calibrated, maintained, and operated on the three (3) selective catalytic reduction systems, used in conjunction with the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3 for measuring operating temperature. From the date of startup until the stack test results are available, the Permittee shall operate the SCR inlet temperature at or above the 3-hour average temperature of 550ºF.

For the purpose of this condition, continuous means no less than once per every fifteen (15) minutes. The output of this system shall be recorded as a 3-hour average.

(ii) The Permittee shall determine the 3-hour average inlet temperature from the most recent valid stack test that demonstrates compliance with limits in Condition D.1.2(h).

(iii) On and after the date the stack test results are available, the Permittee shall operate the one (1) selective catalytic reduction system, at or above the 3-hour average inlet temperature as observed during the compliant stack test.

(iv) If the 3-hour average inlet temperature falls below the above mentioned 3-hour average inlet temperature, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A 3-hour average inlet temperature reading below the above mentioned 3-hour average inlet temperature is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(c) Ammonia injection rate:

(i) A continuous monitoring system shall be calibrated, maintained, and operated on the three (3) selective catalytic reduction systems, used in conjunction with the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3 for measuring the ammonia injection rate. From the date of startup until the stack test results are available, the Permittee shall maintain an ammonia injection rate at or above the one-hour injection rate of 0.26 pounds per hour.

For the purpose of this condition, continuous means no less than once per fifteen (15) minutes. The output of this system shall be recorded as a one-hour average.

(ii) The Permittee shall determine the one-hour average injection rates from the most recent valid stack test that demonstrates compliance with limits in Condition D.1.2(h).

(iii) On and after the date the stack test results are available, the Permittee shall inject ammonia at or above the one-hour average injection rates as observed during the compliant stack test.

(iv) When for any one reading the one-hour injection rate falls below the above mentioned one-hour injection rate, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the response steps required by this condition. A one-hour average that is outside the appropriate injection rate is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

D.1.18 Catalytic Oxidation System Temperature Monitoring

(a) A daily monitoring system shall be calibrated, maintained, and operated on the oxidation catalyst for measuring operating temperature. From the date of startup until the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 3-hour average temperature of 425°F.

(b) The Permittee shall determine the 3-hour average temperature from the latest valid stack test that demonstrates compliance with limits in Conditions D.1.2(i), D.1.2(j), and D.1.3.

(c) On and after the date the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 3-hour average temperature as observed during the latest compliant stack test.

(d) If the daily temperature is greater than the above mentioned 3-hour average temperature, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

D.1.19 Catalytic Oxidation System Duct Pressure or Fan Amperage

(a) The Permittee shall determine the appropriate duct pressure or fan amperage from the latest valid stack test that demonstrates compliance with the limits in Conditions D.1.2(i), D.1.2(j), and D.1.3.

(b) The duct pressure or fan amperage shall be observed at least once per day when the oxidation catalyst is in operation. On and after the date the stack test results are available, the duct pressure or fan amperage shall be maintained within the normal range as established in latest compliant stack test.

(c) When, for any one reading, the duct pressure or fan amperage is outside the above mentioned range, the Permittee shall take a reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

D.1.20 Flare Pilot Flame

In order to assure compliance with Condition D.1.2(i), the Permittee shall monitor the presence of a flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame when the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor are in operation.

D.1.21 Bag Leak Detection System (BLDS)

The Permittee shall comply with the following:

(a) The Permittee shall install and operate a continuous bag leak detection system (BLDS) for each of the baghouses controlling the feedstock storage buildings (FDSTG-1, FDSTG-2, and FDSTG-3) and feedstock dryers (DRYER-1, DRYER-2, and DRYER-3), and each of the filters controlling the ash silos (ASH1, ASH2, and ASH3) and bed media silos (BMS1, BMS2, and BMS3).

(b) The BLDS shall meet the following requirements:

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loading.

(3) The bag leak detection system must be equipped with an alarm system that will alarm when an increase in relative particulate loading is detected over a preset level established or verified during a stack test or established according to paragraph (4). The alarm must be located such that it can be heard by the appropriate plant personnel.

(4) The bag leak detection system shall be installed and operated in a manner consistent with available written guidance from the U.S. Environmental Protection Agency or the manufacturer's written specifications and recommendations for installation, operation, and adjustment of the system.

(5) In no event shall the sensitivity be increased by more than 100 percent or decreased by more than 50 percent over a 365 day period unless such adjustment follows a complete baghouse or filter inspection, which demonstrates the baghouse or filter, is in good operating condition.

(6) Failure to take response steps shall be considered a deviation from this permit.

(7) Whenever a BLDS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more during operation of the relevant feedstock storage building (FDSTG-1, FDSTG-2, or FDSTG-3) or feedstock dryer (DRYER-1, DRYER-2, or DRYER-3), ash silos (ASH1, ASH2, and ASH3), and bed media silos (BMS1, BMS2, and BMS3), the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to take visible emission readings from the relevant unit stack.

(A) Visible emission readings of the applicable exhaust stack(s) from the baghouse(s) or filter(s) shall be performed at least once per day during normal daylight operations.

(B) These observations shall be taken in accordance with 40 CFR 60 Appendix A, Method 9 for at least two six (6) minute averages.

(C) If abnormal emissions are observed, the Permittee shall take a reasonable response. Section C.15 – Response to Excursions or Exceedances contains the Permittee's obligations with regard to the

reasonable response steps required by this condition. Abnormal emissions are not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

D.1.22 Broken or Failed Bag Detection

(a) For a single compartment baghouses controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

(b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit has been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the emissions unit. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

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

D.1.23 SRU - Hydrogen Sulfide (H_2S) Process Gas Sampling and Analysis

(a) The Permittee shall sample and analyze the exhaust gas stream from the Sulfur Removal Unit (SRU) once per day in order to determine the H_2S content. When for any one reading, the H_2S content of the exhaust gas stream from the SRU is greater than 20 ppmv, the Permittee shall take a reasonable response step. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(b) The instrument used for determining the H2S content shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

Record Keeping and Reporting Requirements [326 IAC 2-8-4(3)]

D.1.24 Record Keeping Requirements

(a) To document the compliance status with Conditions D.1.2(b) and D.1.2(e), the Permittee shall maintain records of actual hours of operation of the emergency generator and fire pump engine per month.

(b) To document the compliance status with Conditions D.1.2(h), D.1.2(i), and D.1.2(j), the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) below shall be taken monthly and shall be complete and sufficient to establish compliance with Conditions D.1.2(h), D.1.2(i), and D.1.2(j).

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

(2) Actual fuel usage and heat input for the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater for each fuel used at the source since the last compliance determination period.

(3) Actual records of the number of hours the FT Reactor purge gas is vented to the flare during startup and shutdown events since the last compliance determination period.

(4) Actual wastewater flow and VOC concentration since the last compliance determination period.

(5) Actual VOC emissions from the storage tanks since the last compliance determination period.

(6) Calculated NOx, VOC, and CO emissions for each month and each determination period.

(c) To document the compliance status of Condition D.1.7, the Permittee shall maintain records of the weekly wastewater flow rate and VOC concentration from the wastewater treatment system.

(d) To document the compliance status of Condition D.1.15, the Permittee shall maintain records of the weekly purge gas stream sampling and analysis. The Permittee shall include in its daily record when a sample was not taken and the reason for the lack of a sample (e.g., the process did not operate that day). The Permittee shall include in its daily record when a sample was not analyzed and the reason for the lack of an analysis (e.g., the process did not operate that day).

(e) To document the compliance status with Condition D.1.17, the Permittee shall maintain records in accordance with (1) through (3) below. Records maintained for (1) through (3) below shall be taken monthly and shall be complete and sufficient to establish compliance with Condition D.1.17.

(1) The Permittee shall maintain daily records of the pressure drop across the three (3) selective catalytic reduction systems, controlling the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading (e.g., the process did not operate that day).

(2) The Permittee shall maintain continuous temperature records for the one (1) selective catalytic reduction system, and the 3-hour average temperature used to demonstrate compliance during the most recent compliant stack test.

(3) The Permittee shall maintain records of the one-hour average ammonia injection rate into the three (3) selective catalytic reduction systems, used in conjunction with the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3.

(f) To document the compliance status with Condition D.1.18, the Permittee shall maintain daily temperature records for the oxidation catalyst and the 3-hour average temperature used to demonstrate compliance during the most recent compliant stack test.

(g) To document the compliance status with Condition D.1.19, the Permittee shall maintain daily records of the duct pressure or fan amperage for the oxidation catalyst. The Permittee shall include in its daily record when a pressure or fan amperage reading is not taken and the reason for the lack of the reading (e.g., the process did not operate that day).

(h) To document the compliance status with Condition D.1.20, the Permittee shall maintain records of presence of pilot flame for the flare. The Permittee shall include in its record

when the readings are not taken and the reason for the lack of the readings (e.g., biogas was not routed to the flare).

(i) To document the compliance status with Condition D.1.21, the Permittee shall maintain records of the dates and times of all bag leak detection system alarms, the cause of each alarm, and an explanation of all corrective actions taken.

(j) To document the compliance status of Condition D.1.23, the Permittee shall maintain records of the Sulfur Removal Unit (SRU) exhaust gas stream sampling and analysis. The Permittee shall include in its daily record when a sample was not taken and the reason for the lack of a sample (e.g., the process did not operate that day). The Permittee shall include in its daily record when a sample was not analyzed and the reason for the lack of a analysis (e.g., the process did not operate that day).

(k) Pursuant to 326 IAC 8-9-6(a) and (c), the Permittee shall maintain the following records for the life of the stationary storage vessels and submit a report to IDEM, OAQ containing the following for each vessel:

(1) The vessel identification number;

(2) The vessel dimensions; and

(3) The vessel capacity.

(l) Pursuant to 326 IAC 8-9-6(h), the owner or operator of each vessel with a design capacity greater than or equal to thirty-nine thousand (39,000) gallons storing a liquid with a maximum true vapor pressure, as measured in accordance with subsection (f), that is normally less than seventy-five hundredths (0.75) psia shall maintain a record and notify the department within thirty (30) days when the maximum true vapor pressure of the liquid exceeds seventy-five hundredths (0.75) psia.

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

D.1.25 Record Keeping Requirements for CEMS [326 IAC 2-8-4(3)(A)(iii)] [326 IAC 3-5]

(a) The Permittee shall record the output of the continuous monitoring system(s) pounds per MMBtu and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

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

(c) To document the compliance status with condition D.1.16, the Permittee shall record the ammonia flow rate and inlet duct temperature of the SCR at least four (4) times per hour until the primary CEMS or a backup CEMS is brought online. The Permittee shall include in its record, the downtime of the CEMS, reasons of the breakdown, efforts to correct the problem, and when an ammonia flow rate and/or inlet duct temperature reading is not taken during the CEMS downtime and the reason for the lack of a reading (e.g., the process did not operate during that time).

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

D.1.26 Reporting Requirements

Quarterly summaries of the information to document compliance status with Conditions D.1.2(b), D.1.2(e), D.1.2(h), D.1.2(i), and D.1.2(j) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meet the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

D.1.27 Reporting Requirements for CEMS [326 IAC 2-8-4(3)(A)(iii)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

The report submitted by the Permittee does require a certification that meet the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

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

(1) date of downtime;

(2) time of commencement;

(3) duration of each downtime;

(4) reasons for each downtime; and

(5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meet the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

SECTION E.1 NSPS

Emissions Unit Description:

(h) One (1) utility boiler, identified as BOIL, approved in 2022 for construction, with a maximum heat input capacity of 249.20 MMBtu/hr for natural gas and 36.80 MMBtu/hr for purge gas, using a SCR for NOx control and an oxidation catalyst for VOC and CO control, and exhausting to stack SV10. The utility boiler is equipped with a continuous emission monitoring systems (CEMS) for measuring NOx and O_2 (or CO_2) emissions from the SCR system.

Under the 40 CFR 60, Subpart Db, this is considered an affected facility.

(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 2-8-4(1)]

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Db.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

E.1.2 Industrial-Commercial-Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Db]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Db (included as Attachment B to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

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

SECTION E.2 NSPS

Emissions Unit Description:

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:

(4) Three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3; and

Under 40 CFR 60, Subpart Dc, the heat recovery steam generators (HRSGs) are considered affected facilities.

(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 2-8-4(1)]

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

E.2.2 Small Industrial-Commercial-Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Dc]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Dc (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.40c(a), (b), and (c)
(2) 40 CFR 60.41c
(3) 40 CFR 60.48c(a) and (g)

SECTION E.3 **NSPS**

Emissions Unit Description:

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:

(1) Three (3) steam reformers, equipped with three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, with a maximum heat input capacity of 75.6 MMBtu/hr, each, using a SCR system for NOx control, and exhausting to stacks SV5, SV6, and SV7;

(2) Three (3) carbon trim cells (CTC);

(3) Three (3) partial oxidation (POx) units;

(4) Three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3; and

Under 40 CFR 60, Subpart Dc, the heat recovery steam generators (HRSGs) are considered affected facilities.

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr, and exhausting to stack SV9.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

Under 40 CFR 60, Subpart RRR, the gasifier trains and related processes are considered affected facilities.

(f) One (1) sulfur removal unit, identified as SRU, approved in 2022 for construction, with a maximum airflow rate of 27,068 acfm, using an amine-based acid gas removal system to remove hydrogen sulfide and carbon dioxide from syngas, and exhausting to stack SV8.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

(q) One (1) truck and railcar loadout system, identified as TRC, approved in 2022 for construction, with a maximum throughput rate of 34,000,000 gallons of synthetic paraffinic kerosene (SPK) per year, using flare LOAD as control, which is supplemented by natural gas, has a maximum heat input capacity of 16.60 MMBtu/hr, equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr, and exhausting through stack SV19.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

(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 2-8-4(1)]

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart VVa.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

E.3.2 Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 NSPS [326 IAC 12] [40 CFR Part 60, Subpart VVa]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart VVa (included as Attachment D to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.480a(a), (b), (c), and (d)
(2) 40 CFR 60.481a
(3) 40 CFR 60.482-1a
(4) 40 CFR 60.482-2a
(5) 40 CFR 60.482-3a
(6) 40 CFR 60.482-4a
(7) 40 CFR 60.482-5a
(8) 40 CFR 60.482-6a
(9) 40 CFR 60.482-7a
(10) 40 CFR 60.482-8a
(11) 40 CFR 60.482-9a
(12) 40 CFR 60.482-10a
(13) 40 CFR 60.482-11a
(14) 40 CFR 60.483-1a
(15) 40 CFR 60.483-2a
(16) 40 CFR 60.484a
(17) 40 CFR 60.485a
(18) 40 CFR 60.486a
(19) 40 CFR 60.487a
(20) 40 CFR 60.488a
(21) 40 CFR 60.489a.

SECTION E.4 NSPS

Emissions Unit Description:

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:

(1) Three (3) steam reformers, equipped with three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, with a maximum heat input capacity of 75.6 MMBtu/hr, each, using a SCR system for NOx control, and exhausting to stacks SV5, SV6, and SV7;

(2) Three (3) carbon trim cells (CTC);

(3) Three (3) partial oxidation (POx) units;

(4) Three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3; and

Under 40 CFR 60, Subpart Dc, the heat recovery steam generators (HRSGs) are considered affected facilities.

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr, and exhausting to stack SV9.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

Under 40 CFR 60, Subpart RRR, the gasifier trains and related processes are considered affected facilities.

(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 2-8-4(1)]

E.4.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart RRR.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

E.4.2 Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes NSPS [326 IAC 12] [40 CFR Part 60, Subpart RRR]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart RRR (included as Attachment E to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.700(a), (b), and (c)(3)
(2) 40 CFR 60.701
(3) 40 CFR 60.705(i), (l)(5), and (n)

SECTION E.5 NSPS

Emissions Unit Description:

Insignificant Activities:

(j) One (1) diesel-fired fire pump engine, identified as PUMP, approved in 2022 for construction, with a maximum capacity of 399 hp, and exhausting to stack SV20.

Under 40 CFR 60, Subpart IIII, this is an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is an affected source.

(k) One (1) diesel-fired emergency generator, identified as EG, approved in 2022 for construction, with a maximum capacity of 28.2 MMBtu/hr, and exhausting to stack SV21.

Under 40 CFR 60, Subpart IIII, this is considered an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is considered a new affected source.

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

New Source Performance Standards (NSPS) Requirements [326 IAC 2-8-4(1)]

E.5.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

E.5.2 Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart IIII (included as Attachment F to the operating permit), which are incorporated by reference as 326 IAC 12.

(a) PUMP:
(1) 40 CFR 60.4200(a)(2)(ii) and (c)
(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(a), (c), (f)(1), (f)(2)(i), (f)(3), and (g)(2)
(7) 40 CFR 60.4212
(7) 40 CFR 60.4214(b)
(8) 40 CFR 60.4218
(9) 40 CFR 60.4219

(10) Table 4
(11) Table 5
(12) Table 8

(b) EG:
(1) 40 CFR 60.4200(a)(2)(i) and (c)
(2) 40 CFR 60.4202(a)(2)
(3) 40 CFR 60.4205(b)
(4) 40 CFR 60.4206
(5) 40 CFR 60.4207(b)
(6) 40 CFR 60.4208(a) and (h)
(7) 40 CFR 60.4209(a)
(8) 40 CFR 60.4211(a), (c), (f)(1), (f)(2)(i), (f)(3), and (g)(1)
(9) 40 CFR 60.4212
(10) 40 CFR 60.4214(b)
(11) 40 CFR 60.4218
(12) 40 CFR 60.4219
(13) Table 5
(14) Table 8

SECTION E.6 NESHAP

Emissions Unit Description:

Insignificant Activities:

(j) One (1) diesel-fired fire pump engine, identified as PUMP, approved in 2022 for construction, with a maximum capacity of 399 hp, and exhausting to stack SV20.

Under 40 CFR 60, Subpart IIII, this is an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is an affected source.

(k) One (1) diesel-fired emergency generator, identified as EG, approved in 2022 for construction, with a maximum capacity of 28.2 MMBtu/hr, and exhausting to stack SV21.

Under 40 CFR 60, Subpart IIII, this is considered an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is considered a new affected source.

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-8-4(1)]

E.6.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart ZZZZ.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

E.6.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment G to the operating permit), which are incorporated by reference as 326 IAC 20-82, for the emission unit(s) listed above:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)
(4) 40 CFR 63.6595(a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

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

FEDERALLY ENFORCEABLE STATE OPERATING PERMIT (FESOP) CERTIFICATION

Source Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.: F089-44042-00660

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:
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

FEDERALLY ENFORCEABLE STATE OPERATING PERMIT (FESOP)
EMERGENCY OCCURRENCE REPORT

Source Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.: F089-44042-00660

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**) daytime 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 2-8-12

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

FESOP Quarterly Report

Source Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.: F089-44042-00660
Facility: Emergency generator
Parameter: Annual hours of operation
Limit: The emergency generator shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Annual Operation (Hours)	Annual Operation (Hours)	Annual Operation (Hours)
	This Month	Previous 11 Months	12 Month Total

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

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

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

FESOP Quarterly Report

Source Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.: F089-44042-00660
Facility: Fire pump engine
Parameter: Annual hours of operation
Limit: The fire pump engine shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Annual Operation (Hours)	Annual Operation (Hours)	Annual Operation (Hours)
	This Month	Previous 11 Months	12 Month Total

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

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

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

FESOP Quarterly Report

Source Name:	Fulcrum Centerpoint, LLC
Source Address:	6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.:	F089-44042-00660
Facility:	Feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater
Parameter:	Total NOx emissions
Limit:	Total NOx emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater shall not exceed 41.91 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	NOx Emissions (Tons)	NOx Emissions (Tons)	NOx Emissions (Tons)
	This Month	Previous 11 Months	12 Month Total

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

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

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

FESOP Quarterly Report

Source Name:	Fulcrum Centerpoint, LLC
Source Address:	6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.:	F089-44042-00660
Facility:	FT Reactor, feedstock dryer, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks
Parameter:	Total VOC emissions
Limit:	Total VOC emissions from FT Reactor, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks shall not exceed 48.12 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	VOC Emissions (Tons)	VOC Emissions (Tons)	VOC Emissions (Tons)
	This Month	Previous 11 Months	12 Month Total

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

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

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

FESOP Quarterly Report

Source Name:	Fulcrum Centerpoint, LLC
Source Address:	6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.:	F089-44042-00660
Facility:	Feedstock dryers, pulse combustors, Utility boiler, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater
Parameter:	Total CO emissions
Limit:	Total CO emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater shall not exceed 83.69 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	CO Emissions (Tons)	CO Emissions (Tons)	CO Emissions (Tons)
	This Month	Previous 11 Months	12 Month Total

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

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
FEDERALLY ENFORCEABLE STATE OPERATING PERMIT (FESOP)
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
FESOP Permit No.: F089-44042-00660

Months: _____ to _____ Year: _____

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

Page 2 of 2

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

Form Completed by:____

Title / Position: ____

Date:____

Phone: ____

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

Fulcrum Centerpoint, LLC
6200 Industrial Highway
Gary, Indiana 46406

Affidavit of Construction

I, _____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in _____ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of _____ for _____.
(Title) (Company Name)

3. By virtue of my position with _____, I have personal
(Company Name)
knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of _____.
(Company Name)

4. I hereby certify that Fulcrum Centerpoint, LLC, 6200 Industrial Highway, Gary, Indiana 46406, completed construction of the biorefinery on _____ in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on April 30, 2021 and as permitted pursuant to New Source Construction Permit and Federally Enforceable State Operating Permit No. F089-44042-00660, Plant ID No. 089-00660 issued on _____.

5. **Permittee, please cross out the following statement if it does not apply:** Additional (operations/facilities) were constructed/substituted as described in the attachment to this document and were not made in accordance with the construction permit.

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature_____
Date_____

STATE OF INDIANA)
)SS

COUNTY OF _____)

Subscribed and sworn to me, a notary public in and for _____ County and State of Indiana

on this _____ day of _____, 20_____. My Commission expires: _____.

Signature_____
Name_____ (typed or printed)

FULCRUM CENTERPOINT BIOREFINERY FUGITIVE DUST CONTROL PLAN

Project Information:

Contact:

Yonge Development Services, LLC
2114 NW 40th Terrace, Ste D-1
Gainesville, FL 32605
Thomas Yonge
(352)213-9674

Responsible Parties:

Owner-Permit Holder
Fulcrum Centerpoint, LLC
4900 Hopyard Road, Suite 220
Pleasanton, CA 94588
(925)224-8241
Rick Barazza – VP, Administrator
Flyn van Ewijk – Director, Project Development

Table of Contents

1 INTRODUCTION

This fugitive dust control plan (Plan) has been prepared by Yonge Development Services (YDS), for Fulcrum Centerpoint (Centerpoint). The Plan provides a detailed description of measures that Centerpoint has in place for the control of fugitive dust emissions during development, construction, and reclamation phases of the Centerpoint Project.

1.1 Plan Objectives

The Objectives of the Plan are outlined below:

- Procedures that Centerpoint personnel will follow to control emissions.
- Fugitive dust levels requiring corrective actions.
- Steps that will be followed to bring emissions within appropriate ranges.
- Steps that Centerpoint will take to demonstrate that corrective procedures are followed and to verify the facility is controlling avoidable fugitive emissions

To meet these objectives, the Fugitive Dust Control Plan:

- Identifies all fugitive emission sources listed in the Federally Enforceable State Operating Permit (FESOP).
- Identify applicable “physical” and “operational” fugitive dust controls implemented.
- Identifies visible emissions observation and corrective action requirements.
- Identifies fugitive dust control recordkeeping requirements.
- Identifies fugitive dust control notification requirements.
- Describes fugitive dust control training elements.

1.2 Plan Administration

Implementation of the Plan will be the responsibility of the Centerpoint Plant Managers, or their designee. These individuals are the designated points of contact for questions or concerns regarding Plan implementation. The Plan will be updated as appropriate.

2 SUMMARY OF OPERATIONAL FUGITIVE DUST SOURCES

This section of the plan summarizes operational activities that could generate fugitive dust at Centerpoint. General types of operational activities that could result in fugitive dust emissions, are outlined below:

2.1 Paved Roads

Minor sources of potential fugitive dust emissions at Centerpoint are due to the transportation of material, equipment, and supplies. Minor fugitive dust emissions are also associated with smaller vehicles used by management and operations personnel. These vehicular sources involve track-out as well as immediate fugitive dust generation. Even when the activities are those of a contractor, Centerpoint is ultimately responsible for the control of these fugitive dust sources on Centerpoint land.

2.2 Stockpiles and Conveyance Systems

All stockpiled material will be kept in enclosed buildings on site. All material conveyance systems will be enclosed.

2.3 Slag Handling Activities

Trivial amounts of potential fugitive dust emissions at Centerpoint are due to the handling of slag, which is collected in either roll-off or hopper bins and later loaded onto trucks and transported to offsite disposal areas. Even when the activities are those of a contractor, Centerpoint is ultimately responsible for the control of these fugitive dust sources on Centerpoint land.

2.4 Other Fugitive Dust Emissions

There are no other fugitive dust emission sources expected at this time. A potential source of fugitive dust emissions is feedstock processing and handling. Feedstock will be handled and processed in enclosed structures; however, controls will be put in place to minimize escape from the structures.

3 CONTROL OF FUGITIVE DUST EMISSIONS

Planning for fugitive dust control requires identifying the relative contribution of each source to total fugitive dust emissions. Once disturbed, exposed areas are the greatest source of fugitive dust emissions at Centerpoint, the controls used on disturbed surfaces are the most important in achieving overall control of fugitive dust emissions from Centerpoint. Centerpoint uses both “physical” controls (i.e., conventional control measures) and “operational” controls ((i.e., “best management practices” (“BMP’s”) designed to enhance or supplement the performance of physical controls)) to control fugitive dust emissions. These controls are discussed in the following sections. Many of the development-related sources of fugitive dust emissions identified in the previous section are controlled by similar measures.

3.1 Physical Controls

The purpose of this section is to provide an overview of the available physical controls for each type of emission source identified in Section 2.

All contracted equipment operators are aware of Centerpoint’s fugitive emission reduction goals, and control measures designed to achieve those goals, as outlined in this plan. They are responsible for permitting individual equipment and following their permits.

Specific physical controls are categorized by general source area in the following sections:

3.1.1 Control of Roadway Fugitive Dust Emissions

Delivery and shipping trucks will be required to adhere to a posted facility speed limit of 20 miles per hour.

All roads and parking lots at Centerpoint will be paved. Control methods for fugitive dust emissions from paved roads and parking lots will be performed as necessary. These methods will include vacuum sweeping, flushing, and/or wet power brooming.

Continued maintenance of the running surface and chemical applications is performed with periodic applications of water and additional palliatives, and periodic grading to maintain and rejuvenate the chemically amended surface. This ongoing maintenance significantly enhances the effectiveness of the chemical dust suppressant for a variety of reasons.

Visible emissions surveys are regularly performed to determine when applications of water or palliatives are necessary. The criteria for reapplying water or palliatives are based on fugitive dust emission evaluations.

3.1.2 Control of Fugitive Dust Emissions from Slag Handling Activities

Pursuant to 326 IAC 6.8-10-3(9), fugitive dust emissions generated during slag handling activities will be required to meet a twenty percent (20%), three (3) minute opacity standard. If necessary, the height from which the slag is dropped into the roll-off or hopper bins and the height from which the slag is loaded into trucks shall be limited to meet the twenty percent (20%), three (3) minute opacity standard, under 326 IAC 6.8-10-3(9).

3.1.3 Control of Fugitive Dust Emissions from Feedstock Processing and Handling

Feedstock from separately permitted Feedstock Processing Facilities (FPFs) will be delivered to Centerpoint in trucks. After receipt, the Feedstock will be unloaded and stored in one (1) of the three (3) separate Feedstock storage buildings, which are each enclosed with solid walls and doors that will be closed when the facility is not in operation or when feedstock deliveries are not being made. Each Feedstock storage building will be equipped with a dust collection system.

Feedstock is conveyed from each storage building to a dedicated gasifier train (three in total). All conveyors are either in an enclosed gallery or in an enclosed drag conveyor casing to prevent dust from escaping. Dust collection units are outside the Feedstock storage buildings. The Feedstock will primarily

be dried at the FPFs prior to being delivered to Centerpoint. However, the Centerpoint may also have Feedstock dryers installed should Feedstock require additional drying after being stored. This will be done with a natural gas heated rotary drum style drying system. The drying process is fully enclosed to mitigate dust generation.

3.2 Operational Controls

Management practices designed to enhance or supplement the performance of physical controls are referred to in this plan as “operational controls.” One of the most important operational controls for fugitive dust emissions is minimizing the “footprint” of disturbed areas. This control is developed by Centerpoint Management, and exercised by Centerpoint Management, trained personnel and contractors, and requires careful planning. Centerpoint Management, trained personnel and contractors, and requires careful planning. Once operations are underway, Centerpoint does not anticipate significant land disturbance on site, but, if necessary, will control the amount of land disturbed at one time by disturbing only that land required to construct a specific project. All contractors are required to maintain their work area as well as any additional areas disturbed.

3.2.1 Specific Operational Controls

All site contractors are required to read this control plan prior to commencement of each job. Design engineers are requested to maintain the smallest footprint possible for new projects.

3.2.2 Contractor and Operator Awareness

The benefits of the Plan are best achieved if operators and contractors are aware of the Plan. Perhaps one of the more important methods employed for fugitive dust control is good judgement exercised by equipment operators. Equipment operators are in a position of providing nearly continuous observations of fugitive dust sources and control measures. Because these operators are made aware of the requirements contained in this plan, they can and do notify appropriate personnel when corrective action is required. In this manner, many or most issues relating to the effective control of fugitive dust are identified and corrected prior to regularly scheduled maintenance.

3.2.3 Training

Centerpoint will developed a training program that is designed to inform operators of their responsibilities and Centerpoint’s regulatory commitments. Procedures for physical and operational controls contained in the plan will be incorporated into the training program. The training is provided to all employees and contractors.

- All Centerpoint Employees will be made aware of this plan and asked to study it.
- All Contractors working on Centerpoint land will be required to read this plan and persons of authority will be asked to sign off that they have read the plan.

4 MONITORING EFFECTIVENESS OF FUGITIVE DUST CONTROLS

Section 2 of the Plan identified sources of fugitive dust emissions from operations, while Section 3 evaluated potentially applicable controls, providing a determination of which controls are used for each emission source. This section of the Plan provides procedures that are implemented to monitor the effectiveness of fugitive dust control measures implemented by Centerpoint. It also provides mechanisms for adjusting dust suppression efforts based on observation results.

Some types of controls by their very nature require monitoring to ensure effective implementation. Specific fugitive dust sources and their respective controls, that require monitoring and documentation for effective implementation, are summarized in Table 1 below.

Fugitive Dust Emission Source	Controls	Monitoring Procedure
On-Site Vehicle-Related Fugitive Dust	Applications of chemical dust suppressants, water, and/or roadway surface maintenance; employee and contractor training. All roads and parking lots will be paved. Vacuum sweeping, flushing, and/or wet power brooming.	Visual monitoring during construction to determine success based on noticeable emissions. Visual monitoring weekly to determine success based on noticeable emissions. A log of all monitoring activities will be maintained (including wind speeds, specific control activity, and date/time).
Slag Handling Activities	If necessary, the height from which the slag is dropped into the roll-off or hopper bins and the height from which the slag is loaded into trucks shall be limited to meet the twenty percent (20%), three (3) minute opacity standard, under 326 IAC 6.8-10-3(9).	Pursuant to 326 IAC 6.8-10-3(9), compliance with this limitation shall be determined by 40 CFR 60, Appendix A, Method 9, except that the opacity standard shall be determined as an average of twelve (12) consecutive observations recorded at fifteen (15) second intervals. Compliance of any operation lasting less than three (3) minutes shall be determined as an average of consecutive observations recorded at fifteen (15) second intervals for the duration of the operation.
Concurrent Reclamation and Landscaping	Minimize disturbed area footprint and re-establish natural foliage cover.	Monitor and log coverage.
Disturbed Lands	Water, chemical dust suppressants, berms, wind fences and/or boundary fencing; landscaping and/or re-seeding of unnecessarily disturbed lands.	Visual monitoring weekly to determine success based on noticeable emissions. A log of all monitoring activities will be maintained (including wind speeds, specific control activity and date/time).

Table 1 - Centerpoint Operation Sources and Controls

The following sections describe actions that will be implemented by Centerpoint to ensure that the controls outlined in Table 1 are applied and are effective during development, construction, and reclamation phases of Centerpoint.

4.1 Monitoring of Roadway Fugitive Dust Controls

As discussed in Section 3, fugitive dust from unpaved roadways is controlled using chemical dust suppressants or water.

Chemical dust suppressants are provided in necessary amounts to meet or exceed the recommended manufacturer's application frequency and rate for unpaved roads with regular traffic use. Re-applications of the chemical suppressants are performed annually or as required by frequent inspection and reporting as weather and roadway conditions permit. Follow-up applications of water and roadway surface processing are conducted, when necessary, as determined by regular observations of fugitive emissions.

Paved roadways and parking lots will be visually monitored for observation of fugitive dust emissions and the previously described control methods will be performed as needed. The project will be monitored daily by onsite staff; any problem areas will be called to the attention of shift supervisors and remedies suggested. In areas where construction is ongoing, immediate notification of the problem will be brought to the attention of the job foreman. If remedies are not taken, the construction office will be contacted. In areas that are exposed, but not under construction, the extent of the problem will be monitored. If additional palliatives or crusting is required, appropriate actions will be taken.

4.2 Monitoring of Slag Handling Activities

If necessary, fugitive dust from slag handling activities shall be controlled to meet the twenty percent (20%), three (3) minute opacity standard, under 326 IAC 6.8-10-3(9) by limiting the height from which the slag is dropped into the roll-off or hopper bins and the height from which the slag is loaded into trucks. Slag handling activities will be visually monitored for opacity emissions and the previously described control methods will be performed as needed.

4.3 Monitoring of Other Physical Controls

If necessary, Centerpoint will use as a chemical palliative to control dust on disturbed surfaces. The application timing is based on monitoring of fugitive dust. The number of water trucks required will vary both the type and extent of operation activities occurring, as well as with seasonal variations. Monitoring of conditions and activities expedites control implementation.

If any area is disturbed, Centerpoint contractors will use water trucks with a nominal capacity of 3,500 gallons and water tankers with a nominal capacity of 8,000 gallons. During disturbance activities, Centerpoint will have one water truck of its own with a capacity of 3,500 gallons. Water trucks will be located near exposed disturbed areas and are filled at various locations available on-site. The distance between wells, storage tanks, and other water supplies from dust-creating activities is minimized to facilitate rapid response. Below is an example of a table for monitoring dust suppressant activities.

DUST CONTROL ACTIVITY	DATE/TIME APPLIED	PALLIATIVE USAGE (GALS/ACRE)	AREAL EXTENT COVERED (ACRES)	LOCATION

Table 2 - Example Water/Palliative Schedule

4.4 Monitoring of Reclamation and Landscaping

Concurrent reclamation practices are implemented to minimize the area of surface land disturbance available for wind erosion. As disturbed area activities are completed, concurrent reclamation of the construction site is implemented. These concurrent reclamation activities include but are not limited to watering, chemical dust suppressants, slope contouring, capping/substrate placement, seedbed preparation, seeding, and landscaping. Concurrent implementation of these activities will act to restore the natural vegetative cover and minimize potential fugitive dust emissions.

5 RECORD-KEEPING AND REPORTING

A log of dust control/abatement activity will be kept on file during the life of the project. Included in this file will be the amount of water used each month on dust control/abatement, contracts for palliatives and dates applied. The dates of all vacuum sweeping, flushing, and wet power brooming activities will be recorded. In addition, all correspondence, bids, etc. will be kept between contractors and Centerpoint, and will be kept on hand for review.

6 NAME AND SIGNATURE OF CENTERPOINT RESPONSIBLE OFFICIAL

Name DATE

7 PLAN MODIFICATION

Centerpoint will update the Plan as necessary. A record of all Plan modifications will be maintained by Centerpoint personnel.

8 REFERENCES

- *Control of Open Fugitive Dust Sources* (EPA – 50/3-88-088).
- *Pollution Prevention Alternatives to Hazardous Materials, Techniques for Dust Prevention and Suppression* (Publication No. 96433).

Attachment B

Federally Enforceable State Operating Permit (FESOP) No: F089-44042-00660

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Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

§60.40b Applicability and delegation of authority.

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

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

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

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

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

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

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

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

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

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

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

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

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

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

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

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

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

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

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

§60.41b Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Natural gas means:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) The equipment is attached to a foundation.

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

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

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

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

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

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

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

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

§60.42b Standard for sulfur dioxide (SO2).

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

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

Where:

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§60.43b Standard for particulate matter (PM).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§60.44b Standard for nitrogen oxides (NOX).

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

	Nitrogen oxide emission limits (expressed as NO_2) heat input	
Fuel/steam generating unit type	**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

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(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 only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

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

Where:

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

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

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

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

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

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

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

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

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural

gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

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

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

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

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

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

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

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

amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

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

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

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

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

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

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

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

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

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

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

Where:

%P_s = Potential SO_2 emission rate, percent;

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

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

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

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

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

Where:

E_{ho}^{o} = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

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

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

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

(ii) To compute the percent of potential SO_2 emission rate ($\%P_s$), an adjusted $\%R_g$ ($\%R_g^o$) is computed from the adjusted E_{ao}^o from paragraph (b)(3)(i) of this section and an adjusted average SO_2 inlet 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_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 hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

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

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

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

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

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

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

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

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily

average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) The dry basis F factor; and

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

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

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

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

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

generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

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

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

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

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

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

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

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

Where:

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

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

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

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

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

(ii) Method 7E of appendix A of this part or Method 320 of appendix A of part 63 shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

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

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

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

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

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

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under §60.44b using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63, or other approved reference methods.

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

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

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

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

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

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

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS

specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

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

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

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

(ii) [Reserved]

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

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

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

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

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

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

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

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

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

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§60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent

reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

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

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

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

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

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

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the sampling location for Method 6B of appendix A of this part. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in Section 3.2 and the applicable procedures in Section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C or Method 320 of appendix A of part 63 of this chapter and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part, 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

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

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

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

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

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

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

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

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

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

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

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

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

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 79 FR 11249, Feb. 27, 2014]

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

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under §60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate

compliance with the applicable limit in §60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

z = Fraction of total heat input derived from coal.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§60.49b Reporting and recordkeeping requirements.

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

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

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

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

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

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

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

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

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

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

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

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil,

natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar date;

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

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

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

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

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

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

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

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

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

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

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

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

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

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

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

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

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

RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

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

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

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

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

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

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

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

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b(i).

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_X standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

Air ratio control damper is defined as the part of the low NO_X burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_X technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_X standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_X standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_X.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_X.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Attachment C

Federally Enforceable State Operating Permit (FESOP) No: F089-44042-00660

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

§ 60.40c Applicability and delegation of authority.

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

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

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

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

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

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

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

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

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

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

§ 60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

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

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

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

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

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

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

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

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

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

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

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

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

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

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

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

Natural gas means:

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

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

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

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

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

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

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

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

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

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

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

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

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

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

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

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

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

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

§ 60.42c Standard for sulfur dioxide (SO2).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.43c Standard for particulate matter (PM).

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

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

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

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

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

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

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

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

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification

after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

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

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

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

Where:

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

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

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

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

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

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

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

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

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

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

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

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

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

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

§ 60.46c Emission monitoring for sulfur dioxide.

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

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

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

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

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

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

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

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

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when

calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

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

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

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

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

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

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

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

the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

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

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

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

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

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

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

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

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

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

operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

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

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

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

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

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

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

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

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

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

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

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

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

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

§ 60.48c Reporting and recordkeeping requirements.

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

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

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

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

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

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

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

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

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar dates covered in the reporting period.

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

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

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

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

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

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

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

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

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

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

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

(1) For distillate oil:

(i) The name of the oil supplier;

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

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

(2) For residual oil:

(i) The name of the oil supplier;

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

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

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

(3) For coal:

(i) The name of the coal supplier;

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

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

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

(4) For other fuels:

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

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

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

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

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

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

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

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

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

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

Attachment D

Federally Enforceable State Operating Permit (FESOP) No: F089-44042-00660

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart VVa—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

SOURCE: 72 FR 64883, Nov. 16, 2007, unless otherwise noted.

§ 60.480a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482-1a through 60.482-11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482-1a through 60.482-11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482-1a through 60.482-11a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482-1a through 60.482-11a.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§ 60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions

required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§ 60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of § 60.485a(d), (e), and (f), and § 60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

(f) *Stay of standards.* (1) Owners or operators that start a new, reconstructed, or modified affected source prior to November 16, 2007 are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER .

(i) The definition of “capital expenditure” in § 60.481a of this subpart. While the definition of “capital expenditure” is stayed, owners or operators should use the definition found in § 60.481 of subpart VV of this part.

(ii) [Reserved]

(2) Owners or operators are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER .

(i) The definition of “process unit” in § 60.481a of this subpart. While the definition of “process unit” is stayed, owners or operators should use the following definition:

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

(ii) The method of allocation of shared storage vessels in § 60.482-1a(g) of this subpart.

(iii) The standards for connectors in gas/vapor service and in light liquid service in § 60.482-11a of this subpart.

[72 FR 64883, Nov. 16, 2007, as amended at 73 FR 31375, June 2, 2008]

§ 60.481a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: Y = 1.0 − 0.575 log X, where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

Subpart applicable to facility	Value of B to be used in equation
VVa	12.5
GGGa	7.0

Closed-loop system means an enclosed system that returns process fluid to the process.

Closed-purge system means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007-2300).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e).

In-situ sampling systems means nonextractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

Initial calibration value means the concentration measured during the initial calibration at the beginning of each day required in § 60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482-1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482-2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482-3a(f), and 60.482-10a(f)(1)(ii), is re-monitored as specified in § 60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Storage vessel means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in § 60.2 Definitions.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, in § 60.481a, the definitions of “capital expenditure” and “process unit” were stayed until further notice.

§ 60.482-1a Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§ 60.482-1a through 60.482-10a or § 60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§ 60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, and 60.482-10a as provided in § 60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, or 60.482-10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§ 60.482-2a through 60.482-10a if it is identified as required in § 60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§ 60.482-2a through 60.482-11a if it is identified as required in § 60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§ 60.482-2a, 60.482-7a, and 60.483.2a:

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.* , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, in § 60.482-1a, paragraph (g) was stayed until further notice.

§ 60.482-2a Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b), except as provided in § 60.482-1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first

time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in § 60.482-1a(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in § 60.482-1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in § 60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482-10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in § 60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of § 60.482-10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§ 60.482-3a Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482-1a(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482-10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of § 60.482-10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.485a(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator

demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482-4a Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482-9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in § 60.482-9a.

§ 60.482-5a Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in § 60.482-1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482-10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482-6a Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482-7a Standards: Valves in gas/vapor service and in light liquid service.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1a(c) and (f), and §§ 60.483-1a and 60.483-2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1a(c), and §§ 60.483-1a and 60.483-2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with § 60.483-1a or § 60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in § 60.483-2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through § 60.14 or § 60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482-8a Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in § 60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§ 60.482-2a(c)(2) and 60.482-7a(e).

§ 60.482-9a Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482-10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

§ 60.482-10a Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); and

(ii) Conduct annual inspections according to the procedures in § 60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§ 60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486a(c).

(4) For each inspection conducted in accordance with § 60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.482-11a Standards: Connectors in gas/vapor service and in light liquid service.

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in § 60.482-1a(c), § 60.482-10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in § 60.485a(b) and, as applicable, § 60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in § 60.485a(b).

C_t = Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors* . (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need

not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, § 60.482-11a was stayed until further notice.

§ 60.483-1a Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482-7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in § 60.485a(h).

§ 60.483-2a Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in § 60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with § 60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

§ 60.484a Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER .

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

§ 60.485a Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$V_{max} = K_1 + K_2 H_T$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component "i," ppm

H_i = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference-see § 60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see § 60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with § 60.483-1a or § 60.483-2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$\%V_L = (V_L / V_T) * 100$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with § 60.482-7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§ 60.486a Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in § 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482-10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§ 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).

(ii) The designation of equipment as subject to the requirements of § 60.482-2a(e), § 60.482-3a(i), or § 60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482-4a.

(4)(i) The dates of each compliance test as required in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and § 60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.

(v) Results of each calibration drift assessment required by § 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in § 60.482-11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to § 60.482-4a.

(f) The following information pertaining to all valves subject to the requirements of § 60.482-7a(g) and (h), all pumps subject to the requirements of § 60.482-2a(g), and all connectors subject to the requirements of § 60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with § 60.483-2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§ 60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of § 60.7(b) and (d) do not apply to affected facilities subject to this subpart.

§ 60.487a Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7a(f).

(3) Number of pumps subject to the requirements of § 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2a(e) and those pumps complying with § 60.482-2a(f).

(4) Number of compressors subject to the requirements of § 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of § 60.482-3a(i) and those compressors complying with § 60.482-3a(h).

(5) Number of connectors subject to the requirements of § 60.482-11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482-7a(b) or § 60.483-2a,

(ii) Number of valves for which leaks were not repaired as required in § 60.482-7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in § 60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482-2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in § 60.482-3a(f),

(vi) Number of compressors for which leaks were not repaired as required in § 60.482-3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in § 60.482-11a(b)

(viii) Number of connectors for which leaks were not repaired as required in § 60.482-11a(d), and

(ix)-(x) [Reserved]

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§ 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

§ 60.488a Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital costs that would be required to construct a comparable new facility” under § 60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under § 60.15, the “fixed capital cost of new components” includes the fixed capital cost of all depreciable components (except components specified in § 60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the “Applicability and designation of affected facility” section of the appropriate subpart.) For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.489a List of chemicals produced by affected facilities.

Process units that produce, as intermediates or final products, chemicals listed in § 60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006.

Attachment E

Federally Enforceable State Operating Permit (FESOP) No: F089-44042-00660

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Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

SOURCE: 58 FR 45962, Aug. 31, 1993, unless otherwise noted.

§60.700 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.707 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after June 29, 1990:

(1) Each reactor process not discharging its vent stream into a recovery system.

(2) Each combination of a reactor process and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any reactor process that is designed and operated as a batch operation is not an affected facility.

(2) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§60.702(c); 60.704 (d), (e), and (f); and 60.705 (g), (l)(1), (l)(6), and (t).

(3) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than 1 gigagram per year (1,100 tons per year) is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in §60.705 (i), (l)(5), and (n).

(4) Each affected facility operated with a vent stream flow rate less than 0.011 scm/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.704(g) and §70.705 (h), (l)(4), and (o).

(5) If the vent stream from an affected facility is routed to a distillation unit subject to subpart NNN and has no other releases to the air except for a pressure relief valve, the facility is exempt from all provisions of this subpart except for §60.705(r).

(6) Any reactor process operating as part of a process unit which produces beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(7) Any reactor process that is subject to the provisions of subpart DDD is not an affected facility.

(8) Each affected facility operated with a concentration of total organic compounds (TOC) (less methane and ethane) in the vent stream less than 300 ppmv as measured by Method 18 or a concentration of TOC in the vent stream less than 150 ppmv as measured by Method 25A is exempt from all provisions of this subpart except for the test method and procedure and the reporting and recordkeeping requirements in §60.704(h) and paragraphs (j), (l)(8), and (p) of §60.705.

(d) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators of process vents that are subject to this subpart may choose to comply with the provisions of 40 CFR part 65, subpart D, to satisfy the requirements of §§60.702 through 60.705 and 60.708. The provisions of 40 CFR part 65 also satisfy the criteria of paragraphs (c)(2), (4), and (8) of this section. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

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

(3) *Compliance date.* Owners or operators who choose to comply with 40 CFR part 65, subpart D at initial startup shall comply with paragraphs (d)(1) and (2) of this section for each vent stream on and after the date on which the initial performance test is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial startup, whichever date comes first.

(4) *Initial startup notification.* Each owner or operator subject to the provisions of this subpart that chooses to comply with 40 CFR part 65, subpart D, at initial startup shall notify the Administrator of the specific provisions of 40 CFR 65.63(a)(1), (2), or (3), with which the owner or operator has elected to comply. Notification shall be submitted with the notifications of initial startup required by 40 CFR 65.5(b).

(NOTE: The intent of these standards is to minimize emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of TOC, measured as TOC less methane and ethane. This emission limit reflects the performance of BDT.)

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 78279, Dec. 14, 2000]

§60.701 Definitions.

As used in this subpart, all terms not defined here shall have the meaning given them in the Act and in subpart A of part 60, and the following terms shall have the specific meanings given them.

Batch operation means any noncontinuous reactor process that is not characterized by steady-state conditions and in which reactants are not added and products are not removed simultaneously.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

By compound means by individual stream components, not carbon equivalents.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Combustion device means an individual unit of equipment, such as an incinerator, flare, boiler, or process heater, used for combustion of a vent stream discharged from the process vent.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes.

Flame zone means the portion of the combustion chamber in a boiler occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is present in a line.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. If there is energy recovery, the energy recovery section and the combustion chambers are not of integral design. That is, the energy recovery section and the combustion section are not physically formed into one manufactured or assembled unit but are joined by ducts or connections carrying flue gas.

Primary fuel means the fuel fired through a burner or a number of similar burners. The primary fuel provides the principal heat input to the device, and the amount of fuel is sufficient to sustain operation without the addition of other fuels.

Process heater means a device that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in §60.707. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in §60.707 which is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

Reactor processes are unit operations in which one or more chemicals, or reactants other than air, are combined or decomposed in such a way that their molecular structures are altered and one or more new organic compounds are formed.

Recovery device means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same vent stream.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge results from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Secondary fuel means a fuel fired through a burner other than a primary fuel burner. The secondary fuel may provide supplementary heat in addition to the heat provided by the primary fuel.

Total organic compounds or TOC means those compounds measured according to the procedures in §60.704(b)(4). For the purposes of measuring molar composition as required in §60.704(d)(2)(i) and §60.704(d)(2)(ii), hourly emission rate as required in §60.704(d)(5) and §60.704(e), and TOC concentration as required in §60.705(b)(4) and §60.705(f)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded.

Total resource effectiveness or TRE index value means a measure of the supplemental total resource requirement per unit reduction of TOC associated with a vent stream from an affected reactor process facility, based on vent stream flow rate, emission rate of TOC, net heating value, and corrosion properties (whether or not the vent stream contains halogenated compounds), as quantified by the equation given under §60.704(e).

Vent stream means any gas stream discharged directly from a reactor process to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks.

§60.702 Standards.

Each owner or operator of any affected facility shall comply with paragraph (a), (b), or (c) of this section for each vent stream on and after the date on which the initial performance test required by §60.8 and §60.704 is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial start-up, whichever date comes first. Each owner or operator shall either:

(a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(b) Combust the emissions in a flare that meets the requirements of §60.18; or

(c) Maintain a TRE index value greater than 1.0 without use of a VOC emission control device.

§60.703 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit specified under §60.702(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox or in the ductwork immediately downstream of the firebox in a position before any substantial heat exchange is encountered.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) A flow indicator that provides a record of vent stream flow diverted from being routed to the incinerator at least once every 15 minutes for each affected facility, except as provided in paragraph (a)(2)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the incinerator, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(b) The owner or operator of an affected facility that uses a flare to seek to comply with §60.702(b) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A heat sensing device, such as an ultraviolet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.

(2) A flow indicator that provides a record of vent stream flow diverted from being routed to the flare at least once every 15 minutes for each affected facility, except as provided in paragraph (b)(2)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the flare, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(c) The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with §60.702(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications the following equipment:

(1) A flow indicator that provides a record of vent stream flow diverted from being routed to the boiler or process heater at least once every 15 minutes for each affected facility, except as provided in paragraph (c)(1)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the boiler or process heater, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) design heat input capacity. Any vent stream introduced with primary fuel into a boiler or process heater is exempt from this requirement.

(d) The owner or operator of an affected facility that seeks to demonstrate compliance with the TRE index value limit specified under §60.702(c) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator:

(1) Where an absorber is the final recovery device in the recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, and a specific gravity monitoring device having an accuracy of ±0.02 specific gravity units, each equipped with a continuous recorder; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(2) Where a condenser is the final recovery device in the recovery system:

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(3) Where a carbon adsorber is the final recovery device unit in the recovery system:

(i) An integrating steam flow monitoring device having an accuracy of ±10 percent, and a carbon bed temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, both equipped with a continuous recorder; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(e) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under §60.702 with a control device other than an incinerator, boiler, process heater, or flare; or a recovery device other than an absorber, condenser, or carbon adsorber, shall provide to the Administrator information describing the operation of the control device or recovery device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

§60.704 Test methods and procedures.

(a) For the purpose of demonstrating compliance with §60.702, all affected facilities shall be run at full operating conditions and flow rates during any performance test.

(b) The following methods in appendix A to this part, except as provided under §60.8(b), shall be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified under §60.702(a).

(1) Method 1 or 1A, as appropriate, for selection of the sampling sites. The control device inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device and after the recovery system.

(2) Method 2, 2A, 2C, or 2D, as appropriate, for determination of the gas volumetric flow rates.

(3) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the oxygen concentration ($\%O_{2d}$) for the purposes of determining compliance with the 20 ppmv limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent O_2 (Cc) shall be computed using the following equation:

$$C_C = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined.

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) shall be determined using the following equation:

$$R = \frac{E_i - E_o}{E_i} \times 100$$

where:

R=Emission reduction, percent by weight.

E_i = Mass rate of TOC entering the control device, kg TOC/hr.

E_o = Mass rate of TOC discharged to the atmosphere, kg TOC/hr.

(iii) The mass rates of TOC (E_i, E_o) shall be computed using the following equations:

$$E_i = K_2 \sum_{j=1}^{n} C_{ij} M_{ij} Q_i$$

$$E_i = K_2 \sum_{j=1}^{n} C_{oj} M_{ij} Q_o$$

where:

C_{ij}. C_{oj} = Concentration of sample component "j" of the gas stream at the inlet and outlet of the control device, respectively, dry basis, ppm by volume.

M_{ij}, M_{oj} = Molecular weight of sample component "j" of the gas stream at the inlet and outlet of the control device, respectively, g/g-mole (lb/lb-mole).

Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device, respectively, dscm/min (dscf/hr).

K_2 = Constant, 2.494×10^{-6} (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

(iv) The TOC concentration (C_{TOC}) is the sum of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

C_j = Concentration of sample components "j", dry basis, ppm by volume.

n=Number of components in the sample.

(5) The requirement for an initial performance test is waived, in accordance with §60.8(b), for the following:

(i) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek compliance with §60.702(a).

(ii) When a vent stream is introduced into a boiler or process heater with the primary fuel.

(iii) The Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(6) For purposes of complying with the 98 weight-percent reduction in §60.702(a), if the vent stream entering a boiler or process heater with a design capacity less than 44 MW (150 million Btu/hour) is introduced with the combustion air or as secondary fuel, the weight-percent reduction of TOC (minus methane and ethane) across the combustion device shall be determined by comparing the TOC (minus methane and ethane) in all combusted vent streams, primary fuels, and secondary fuels with the TOC (minus methane and ethane) exiting the combustion device.

(c) When a flare is used to seek to comply with §60.702(b), the flare shall comply with the requirements of §60.18.

(d) The following test methods in appendix A to this part, except as provided under §60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under §60.702(b) and for determining the process vent stream TRE index value to determine compliance under §60.700(c)(2) and §60.702(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in §60.704 (d)(2) and (d)(3) shall be, except for the situations outlined in paragraph (d)(1)(ii) of this section, prior to the inlet of any control device, prior to any postreactor dilution of the stream with air, and prior to any postreactor introduction of halogenated compounds into the process vent stream. No traverse site selection method is needed for vents smaller than 4 inches in diameter.

(ii) If any gas stream other than the reactor vent stream is normally conducted through the final recovery device:

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which any nonreactor stream or stream from a nonaffected reactor process is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 at the inlet to the final recovery device after the introduction of any vent stream and at the outlet of the final recovery device.

(C) This efficiency of the final recovery device shall be applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of any nonreactor stream or stream from a nonaffected reactor process to determine the concentration of TOC in the reactor process vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in §60.704(d) (4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1 \sum_{j=1}^{n} C_j H_j \quad 1 - B_{ws}$$

where:

H_T = Net heating value of the sample, MJ/scm, where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C, as in the definition of Q_s (vent stream flow rate).

K_1 = Constant, 1.740×10^{-7} (l/ppm) (g-mole/scm) (MJ/kcal), where standard temperature for (g-mole/scm) is 20 °C.

C_j = Concentration on a dry basis of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) as indicated in §60.704(d)(2).

H_j = Net heat of combustion of compound j, kcal/g-mole, based on combustion at 25 °C and 760 mm Hg. The heats of combustion of vent stream components would be required to be determined using ASTM D2382-76 or 88 or D4809-95 (incorporation by reference as specified in §60.17 of this part) if published values are not available or cannot be calculated.

B_{ws} = Water vapor content of the vent stream, proportion by volume.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2 \sum_{j=1}^{n} C_j M_j Q_s$$

where:

E_{TOC} = Emission rate of TOC in the sample, kg/hr.

K_2 = Constant, 2.494×10^{-6} (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

C_j = Concentration on a dry basis of compound j in ppm as measured by Method 18 as indicated in §60.704(d)(2).

M_j = Molecular weight of sample j, g/g-mole.

Q_s = Vent stream flow rate (dscm/min) at a temperature of 20 °C.

(6) The total vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18.

(e) For purposes of complying with §60.700(c)(2) and §60.702(c), the owner or operator of a facility affected by this subpart shall calculate the TRE index value of the vent stream using the equation for incineration in paragraph (e)(1) of this section for halogenated vent streams. The owner or operator of an affected facility with a nonhalogenated vent stream shall determine the TRE index value by calculating values using both the incinerator equation in (e)(1) of this section and the flare equation in (e)(2) of this section and selecting the lower of the two values.

(1) The equation for calculating the TRE index value of a vent stream controlled by an incinerator is as follows:

$$TRE = \frac{1}{E_{TOC}} \left[a + b(Q_s)^{0.88} + c(Q_s) + d(Q_s)(H_T) + e(Q_s)^{0.88}(H_T)^{0.88} + f(Y_s)^{0.5} \right]$$

(i) Where for a vent stream flow rate (scm/min) at a standard temperature of 20 °C that is greater than or equal to 14.2 scm/min:

TRE=TRE index value.

Q_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in the definition of Q_s.

$Y_s = Q_s$ for all vent stream categories listed in table 1 except for Category E vent streams where $Y_s = (Q_s)(H_T)/3.6$.

E_{TOC} = Hourly emissions of TOC reported in kg/hr.

a, b, c, d, e, and f are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 1.

Table 1—Total Resource Effectiveness Coefficients for Vent Streams Controlled by an Incinerator Subject to the New Source Performance Standards for Reactor Processes

	a	b	c	d	e	f
DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm)≤3.5: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 18.8$	19.18370	0.27580	0.75762	−0.13064	0	0.01025
$18.8 < Q_s \le 699$	20.00563	0.27580	0.30387	−0.13064	0	0.01025
$699 < Q_s \le 1{,}400$	39.87022	0.29973	0.30387	−0.13064	0	0.01449
$1{,}400 < Q_s \le 2{,}100$	59.73481	0.31467	0.30387	−0.13064	0	0.01775
$2{,}100 < Q_s \le 2{,}800$	79.59941	0.32572	0.30387	−0.13064	0	0.02049
$2{,}800 < Q_s \le 3{,}500$	99.46400	0.33456	0.30387	−0.13064	0	0.02291
DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE (MJ/scm)>3.5: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 < Q_s \le 18.8$	18.84466	0.26742	−0.20044	0	0	0.01025
$18.8 < Q_s \le 699$	19.66658	0.26742	−0.25332	0	0	0.01025
$699 < Q_s \le 1{,}400$	39.19213	0.29062	−0.25332	0	0	0.01449
$1{,}400 < Q_s \le 2{,}100$	58.71768	0.30511	−0.25332	0	0	0.01775
$2{,}100 < Q_s \le 2{,}800$	78.24323	0.31582	−0 25332	0	0	0.02049
$2{,}800 < Q_s \le 3{,}500$	97.76879	0.32439	−0.25332	0	0	0.02291
DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm)≤0.48: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 1{,}340$	8.54245	0.10555	0.09030	−0.17109	0	0.01025
$1{,}340 < Q_s \le 2{,}690$	16.94386	0.11470	0.09030	−0.17109	0	0.01449
$2{,}690 < Q_s \le 4{,}040$	25.34528	0.12042	0.09030	−0.17109	0	0.01775
DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 0.48<NET HEATING VALUE (MJ/scm)≤1.9: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 1{,}340$	9.25233	0.06105	0.31937	−0.16181	0	0.01025
$1{,}340 < Q_s \le 2{,}690$	18.36363	0.06635	0.31937	−0.16181	0	0.01449
$2{,}690 < Q_s \le 4{,}040$	27.47492	0.06965	0.31937	−0.16181	0	0.01775
DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 1.9<NET HEATING VALUE (MJ/scm)≤3.6: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 1{,}180$	6.67868	0.06943	0.02582	0	0	0.01025
$1{,}180 < Q_s \le 2{,}370$	13.21633	0.07546	0.02582	0	0	0.01449
$2{,}370 < Q_s \le 3{,}550$	19.75398	0.07922	0.02582	0	0	0.01755

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE (MJ/scm)>3.6: Y_s = *Dilution Flow Rate (scm/min)=(Q_s)* (H_T)/3.6						
$14.2 \le Y_s \le 1{,}180$	6.67868	0	0	−0.00707	0.02220	0.01025
$1{,}180 < Y_s \le 2{,}370$	13.21633	0	0	−0.00707	0.02412	0.01449
$2{,}370 < Y_s \le 3{,}550$	19.75398	0	0	−0.00707	0.02533	0.01755

(ii) For a vent stream flow rate (scm/min) at a standard temperature of 20 °C that is less than 14.2 scm/min:

TRE=TRE index value.

Q_s = 14.2 scm/min.

H_T = (FLOW)(HVAL)/14.2

where the following inputs are used:

FLOW=Vent stream flow rate (scm/min), at a standard temperature of 20 °C.

HVAL=Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in definition of Q_s.

Y_s = 14.2 scm/min for all vent streams except for Category E vent streams, where Y_s = (14.2)(H_T)/3.6.

E_{TOC} = Hourly emissions of TOC reported in kg/hr.

a, b, c, d, e, and f are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 1.

(2) The equation for calculating the TRE index value of a vent stream controlled by a flare is as follows:

$$TRE = \frac{1}{E_{TOC}}\left[a(Q_s) + b(Q_s)^{0.8} + c(Q_s)(H_T) + d(E_{TOC}) + e\right]$$

where:

TRE=TRE index value.

E_{TOC} = Hourly emission rate of TOC reported in kg/hr.

Q_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = Vent stream net heating value (MJ/scm) where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in the definition of Q_s.

a, b, c, d, and e are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 2.

Table 2—Total Resource Effectiveness Coefficients for Vent Streams Controlled by a Flare Subject to the New Source Performance Standards for Reactor Processes

	a	b	c	d	e

H_T<11.2 MJ/scm	2.25	0.288	−0.193	−0.0051	2.08
H_T≥11.2 MJ/scm	0.309	0.0619	−0.0043	−0.0034	2.08

(f) Each owner or operator of an affected facility seeking to comply with §60.700(c)(2) or §60.702(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Examples of process changes include changes in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change on the recovery system.

(1) Where the recalculated TRE index value is less than or equal to 1.0, the owner or operator shall notify the Administrator within 1 week of the recalculation and shall conduct a performance test according to the methods and procedures required by §60.704 in order to determine compliance with §60.702 (a) or (b). Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(2) Where the recalculated TRE index value is less than or equal to 8.0 but greater than 1.0, the owner or operator shall conduct a performance test in accordance with §60.8 and §60.704 and shall comply with §60.703, §60.704 and §60.705. Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(g) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with §60.700(c)(4) shall use Method 2, 2A, 2C, or 2D of appendix A to 40 CFR part 60, as appropriate, for determination of volumetric flow rate.

(h) Each owner or operator seeking to demonstrate that a reactor process vent stream has a TOC concentration for compliance with the low concentration exemption in §60.700(c)(8) shall conduct an initial test to measure TOC concentration.

(1) The sampling site shall be selected as specified in paragraph (d)(1)(i) of this section.

(2) Method 18 or Method 25A of part 60, appendix A shall be used to measure concentration.

(3) Where Method 18 is used to qualify for the low concentration exclusion in §60.700(c)(8), the procedures in §60.704(b)(4) (i) and (iv) shall be used to measure TOC concentration, and the procedures of §60.704(b)(3) shall be used to correct the TOC concentration to 3 percent oxygen. To qualify for the exclusion, the results must demonstrate that the concentration of TOC, corrected to 3 percent oxygen, is below 300 ppm by volume.

(4) Where Method 25A is used, the following procedures shall be used to calculate ppm by volume TOC concentration, corrected to 3 percent oxygen:

(i) Method 25A shall be used only if a single organic compound is greater than 50 percent of total TOC, by volume, in the reactor process vent stream. This compound shall be the principal organic compound.

(ii) The principal organic compound may be determined by either process knowledge or test data collected using an appropriate EPA Reference Method. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current reactor process vent stream conditions.

(iii) The principal organic compound shall be used as the calibration gas for Method 25A.

(iv) The span value for Method 25A shall be 300 ppmv.

(v) Use of Method 25A is acceptable if the response from the high-level calibration gas is at least 20 times the standard deviation of the response from the zero calibration gas when the instrument is zeroed on the most sensitive scale.

(vi) The owner or operator shall demonstrate that the concentration of TOC including methane and ethane measured by Method 25A, corrected to 3 percent oxygen, is below 150 ppm by volume to qualify for the low concentration exclusion in §60.700(c)(8).

(vii) The concentration of TOC shall be corrected to 3 percent oxygen using the procedures and equation in paragraph (b)(3) of this section.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 61778, Oct. 17, 2000]

§60.705 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.702 shall notify the Administrator of the specific provisions of §60.702 (§60.702 (a), (b), or (c)) with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial start-up required by §60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of §60.702 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by §60.704 no later than 180 days from initial start-up.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used or where the reactor process vent stream is introduced as the primary fuel to any size boiler or process heater to comply with §60.702(a), a report containing performance test data need not be submitted, but a report containing the information in §60.705(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a combustion device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined.

(1) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(a) through use of either a thermal or catalytic incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed for a catalytic incinerator), measured at least every 15 minutes and averaged over the same time period of the performance testing, and

(ii) The percent reduction of TOC determined as specified in §60.704(b) achieved by the incinerator, or the concentration of TOC (ppmv, by compound) determined as specified in §60.704(b) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(a) through use of a boiler or process heater:

(i) A description of the location at which the vent stream is introduced into the boiler or process heater, and

(ii) The average combustion temperature of the boiler or process heater with a design heat input capacity of less than 44 MW (150 million Btu/hr) measured at least every 15 minutes and averaged over the same time period of the performance testing.

(3) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(b) through use of a smokeless flare, flare design (i.e., steam-assisted, air-assisted or nonassisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring, and records of all periods of operations during which the pilot flame is absent.

(4) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(c):

(i) Where an absorber is the final recovery device in the recovery system, the exit specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average exit temperature, of the absorbing liquid measured at least every 15 minutes and averaged over the same time period of the performance testing (both measured while the vent stream is normally routed and constituted); or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is routed and constituted normally; or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total steam mass flow measured at least every 15 minutes and averaged over the same time period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration [and within 15 minutes of completion of any cooling cycle(s)], and duration of the carbon bed steaming cycle (all measured while the vent stream is routed and constituted normally); or

(iv) As an alternative to §60.705(b)(4) (i), (ii) or (iii), the concentration level or reading indicated by the organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber, measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.703 (a) and (c) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where a combustion device is used to comply with §60.702(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.702(a) was determined.

(2) For catalytic incinerators, all 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 °C (50 °F) below the average temperature of the vent stream during the most recent performance test at which compliance with §60.702(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the bed during the most recent performance test at which compliance with §60.702(a) was determined.

(3) All 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.702(a) was determined for boilers or process heaters with a design heat input capacity of less than 44 MW (150 million Btu/hr) where the vent stream is introduced with the combustion air or as a secondary fuel.

(4) For boilers or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §60.702(a).

(d) Each owner or operator subject to the provisions of this subpart shall keep records of the following:

(1) Up-to-date, readily accessible continuous records of the flow indication specified under §60.703(a)(2)(i), §60.703(b)(2)(i) and §60.703(c)(1)(i), as well as up-to-date, readily accessible records of all periods and the duration when the vent stream is diverted from the control device.

(2) Where a seal mechanism is used to comply with §60.703(a)(2)(ii), §60.703(b)(2)(ii), and §60.703(c)(1)(ii), a record of continuous flow is not required. In such cases, the owner or operator shall keep up-to-date, readily accessible records of all monthly visual inspections of the seals as well as readily accessible records of all periods and the

duration when the seal mechanism is broken, the bypass line valve position has changed, the serial number of the broken car-seal has changed, or when the key for a lock-and-key type configuration has been checked out.

(e) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the flare pilot flame monitoring specified under §60.703(b), as well as up-to-date, readily accessible records of all periods of operations in which the pilot flame is absent.

(f) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.703(d), as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where an owner or operator seeks to comply with §60.702(c), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final recovery device in a recovery system, and where an organic compound monitoring device is not used:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11 °C (20 °F) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which case he will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final recovery device in a system, and where an organic compound monitoring device is not used, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was more than 6 °C (11 °F) above the average exit (product side) operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final recovery device in a system, and where an organic compound monitoring device is not used:

(i) All carbon bed regeneration cycles during which the total mass steam flow was more than 10 percent below the total mass steam flow during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was more than 10 percent or 5 °C greater, whichever is less stringent, than the carbon bed temperature (in degrees Celsius) during the most recent performance test.

(4) Where an absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic compound monitoring device is used, all 3-hour periods of operation during which the average organic compound concentration level or reading of organic compounds in the exhaust gases is more than 20 percent greater than the exhaust gas organic compound concentration level or reading measured by the monitoring device during the most recent performance test.

(g) Each owner or operator of an affected facility subject to the provisions of this subpart and seeking to demonstrate compliance with §60.702(c) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of recovery equipment or reactors;

(2) Any recalculation of the TRE index value performed pursuant to §60.704(f); and

(3) The results of any performance test performed pursuant to the methods and procedures required by §60.704(d).

(h) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the flow rate cutoff in §60.700(c)(4) shall keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.011 scm/min and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(i) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the design production capacity provision in §60.700(c)(3) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(j) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the low concentration exemption in §60.700(c)(8) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the concentration of the vent stream of the affected facility.

(k) Each owner or operator subject to the provisions of this subpart is exempt from the quarterly reporting requirements contained in §60.7(c) of the General Provisions.

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of §60.700 (c)(2), (c)(3), or (c)(4) or §60.702 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date.

(1) Exceedances of monitored parameters recorded under §60.705 (c), (f), and (g).

(2) All periods and duration recorded under §60.705(d) when the vent stream is diverted from the control device to the atmosphere.

(3) All periods recorded under §60.705(f) in which the pilot flame of the flare was absent.

(4) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in §60.700(c)(4), including a measurement of the new vent stream flow rate, as recorded under §60.705(i). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and E_{TOC}. The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under any of the exemption provisions listed in §60.700(c), except for the total resource effectiveness index greater than 8.0 exemption in §60.700(c)(2), the facility must begin compliance with the requirements set forth in §60.702.

(5) Any change in equipment or process operation, as recorded under paragraph (i) of this section, that increases the design production capacity above the low capacity exemption level in §60.700(c)(3) and the new capacity resulting from the change for the reactor process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and E_{TOC}. The performance test is subject to the requirements of §60.8. The facility must begin compliance with the requirements set forth in §60.702 or §60.700(d). If the facility chooses to comply with §60.702, the facility may qualify for an exemption under §60.700(c)(2), (4), or (8).

(6) Any recalculation of the TRE index value, as recorded under §60.705(g).

(7) All periods recorded under §60.705(d) in which the seal mechanism is broken or the by-pass line valve position has changed. A record of the serial number of the car-seal or a record to show that the key to unlock the bypass line valve was checked out must be maintained to demonstrate the period, the duration, and frequency in which the bypass line was operated.

(8) Any change in equipment or process operation that increases the vent stream concentration above the low concentration exemption level in §60.700(c)(8), including a measurement of the new vent stream concentration, as recorded under §60.705(j). These must be reported as soon as possible after the change and no later than 180 days

after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. If the vent stream concentration is above 300 ppmv as measured using Method 18 or above 150 ppmv as measured using Method 25A, a performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and $E_{TOC.}$ The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under any of the exemption provisions listed in §60.700(c), except for the TRE index greater than 8.0 exemption in §60.700(c)(2), the facility must begin compliance with the requirements set forth in §60.702.

(m) The requirements of §60.705(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with §60.705(l), provided that they comply with the requirements established by the State.

(n) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(3) must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(o) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(4) must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in §60.704.

(p) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(8) must submit to the Administrator an initial report including a concentration measurement using the test method specified in §60.704.

(q) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under §60.702 other than as provided under §60.703 (a), (b), (c), and (d).

(r) Each owner or operator whose reactor process vent stream is routed to a distillation unit subject to subpart NNN and who seeks to demonstrate compliance with §60.700(c)(5) shall submit to the Administrator a process design description as part of the initial report. This process design description must be retained for the life of the process. No other records or reports would be required unless process changes are made.

(s) Each owner or operator who seeks to demonstrate compliance with §60.702 (a) or (b) using a control device must maintain on file a schematic diagram of the affected vent streams, collection system(s), fuel systems, control devices, and bypass systems as part of the initial report. This schematic diagram must be retained for the life of the system.

(t) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(2) must maintain a record of the initial test for determining the total resource effectiveness index and the results of the initial total resource effectiveness index calculation.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 78279, Dec. 14, 2000]

§60.706 Reconstruction.

(a) For purposes of this subpart “fixed capital cost of the new components,” as used in §60.15, includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following June 29, 1990. For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

(b) [Reserved]

§60.707 Chemicals affected by subpart RRR.

Chemical	CAS No.[1]
Acetaldehyde	75-07-0

Chemical	CAS No.[1]
Acetic acid	64-19-7
Acetic anhydride	108-24-7
Acetone	67-64-1
Acetone cyanohydrin	75-86-5
Acetylene	74-86-2
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Adipic acid	124-04-9
Adiponitrile	111-69-3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Alcohols, C-12 or higher, unmixed	
Allyl chloride	107-05-1
Amylene	513-35-9
Amylenes, mixed	
Aniline	62-53-3
Benzene	71-43-2
Benzenesulfonic acid	98-11-3
Benzenesulfonic acid C_{10-16}-alkyl derivatives, sodium salts	68081-81-2
Benzyl chloride	100-44-7
Bisphenol A	80-05-7
Brometone	76-08-4
1,3-Butadiene	106-99-0
Butadiene and butene fractions	
n-Butane	106-97-8
1,4-Butanediol	110-63-4
Butanes, mixed	
1-Butene	106-98-9
2-Butene	25167-67-3
Butenes, mixed	
n-Butyl acetate	123-86-4
Butyl acrylate	141-32-2
n-Butyl alcohol	71-36-3
sec-Butyl alcohol	78-92-2
tert-Butyl alcohol	75-65-0
Butylbenzyl phthalate	85-68-7
tert-Butyl hydroperoxide	75-91-2
2-Butyne-1,4-diol	110-65-6
Butyraldehyde	123-72-8
Butyric anhydride	106-31-0
Caprolactam	105-60-2
Carbon disulfide	75-15-0
Carbon tetrachloride	56-23-5
Chloroacetic acid	79-11-8

Chemical	CAS No.[1]
Chlorobenzene	108-90-7
Chlorodifluoromethane	75-45-6
Chloroform	67-66-3
p-Chloronitrobenzene	100-00-5
Citric acid	77-92-9
Cumene	98-82-8
Cumene hydroperoxide	80-15-9
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1
Cyclohexanone oxime	100-64-1
Cyclohexene	110-83-8
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
1,4-Dichlorobutene	110-57-6
3,4-Dichloro-1-butene	64037-54-3
Dichlorodifluoromethane	75-71-8
Dichlorodimethylsilane	75-78-5
Dichlorofluoromethane	75-43-4
Diethanolamine	111-42-2
Diethylbenzene	25340-17-4
Diethylene glycol	111-46-6
Di-isodecyl phthalate	26761-40-0
Dimethyl terephthalate	120-61-6
2,4-(and 2,6)-dinitrotoluene	121-14-2
	606-20-2
Dioctyl phthalate	117-81-7
Dodecene	25378-22-7
Dodecylbenzene, nonlinear	
Dodecylbenzenesulfonic acid	27176-87-0
Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	106-89-8
Ethanol	64-17-5
Ethanolamine	141-43-5
Ethyl acetate	141-78-6
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride	75-00-3
Ethylene	74-85-1
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene glycol	107-21-1

Chemical	CAS No.[1]
Ethylene glycol monobutyl ether	111-76-2
Ethylene glycol monoethyl ether acetate	111-15-9
Ethylene glycol monomethyl ether	109-86-4
Ethylene oxide	75-21-8
2-Ethylhexyl alcohol	104-76-7
(2-Ethylhexyl) amine	104-75-6
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547-17-8
Formaldehyde	50-00-0
Glycerol	56-81-5
n-Heptane	142-82-5
Heptenes (mixed)	
Hexamethylene diamine	124-09-4
Hexamethylene diamine adipate	3323-53-3
Hexamethylenetetramine	100-97-0
Hexane	110-54-3
Isobutane	75-28-5
Isobutanol	78-83-1
Isobutylene	115-11-7
Isobutyraldehyde	78-84-2
Isopentane	78-78-4
Isoprene	78-79-5
Isopropanol	67-63-0
Ketene	463-51-4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	
Linear alcohols, sulfated, sodium salt, mixed	
Linear alkylbenzene	123-01-3
Maleic anhydride	108-31-6
Mesityl oxide	141-79-7
Methanol	67-56-1
Methylamine	74-39-5
ar-Methylbenzenediamine	25376-45-8
Methyl chloride	74-87-3
Methylene chloride	75-09-2
Methyl ethyl ketone	78-93-3
Methyl isobutyl ketone	108-10-1
Methyl methacrylate	80-62-6
1-Methyl-2-pyrrolidone	872-50-4
Methyl tert-butyl ether	
Naphthalene	91-20-3
Nitrobenzene	98-95-3
1-Nonene	27215-95-8
Nonyl alcohol	143-08-8
Nonylphenol	25154-52-3

Chemical	CAS No.[1]
Nonylphenol, ethoxylated	9016-45-9
Octene	25377-83-7
Oil-soluble petroleum sulfonate, calcium salt	
Pentaerythritol	115-77-5
3-Pentenenitrile	4635-87-4
Pentenes, mixed	109-67-1
Perchloroethylene	127-18-4
Phenol	108-95-2
1-Phenylethyl hydroperoxide	3071-32-7
Phenylpropane	103-65-1
Phosgene	75-44-5
Phthalic anhydride	85-44-9
Propane	74-98-6
Propionaldehyde	123-38-6
Propyl alcohol	71-23-8
Propylene	115-07-1
Propylene glycol	57-55-6
Propylene oxide	75-56-9
Sorbitol	50-70-4
Styrene	100-42-5
Terephthalic acid	100-21-0
Tetraethyl lead	78-00-2
Tetrahydrofuran	109-99-9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75-74-1
Toluene	108-88-3
Toluene-2,4-diamine	95-80-7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471-62-5
1,1,1-Trichloroethane	71-55-6
1,1,2-Trichloroethane	79-00-5
Trichloroethylene	79-01-6
Trichlorofluoromethane	75-69-4
1,1,2-Trichloro-1,2,2-trifluoroethane	76-13-1
Triethanolamine	102-71-6
Triethylene glycol	112-27-6
Vinyl acetate	108-05-4
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4
m-Xylene	108-38-3
o-Xylene	95-47-6
p-Xylene	106-42-3
Xylenes (mixed)	1330-20-7

[1]CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers

assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995]

§60.708 Delegation of authority.

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

(b) Authorities which will not be delegated to States: §60.703(e).

Attachment F

Federally Enforceable State Operating Permit (FESOP) No: F089-44042-00660

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Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Emission Standards for Manufacturers

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) [Reserved]

(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 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder must use diesel fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 85 FR 78463, Dec. 4, 2020]

Other Requirements for Owners and Operators

§60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §60.4201 or §60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all of the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR 89.112 when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent

performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219, July 7, 2016]

Testing Requirements for Owners and Operators

§60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or 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_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Notification, Reports, and Records for Owners and Operators

§60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016]

Special Requirements

§60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in §§60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§60.4202 and 60.4205, and not those for non-emergency engines in §§60.4201 and 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards in 40 CFR 89.112 or 40 CFR 1042.101.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016; 84 FR 61568, Nov. 13, 2019]

§60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§60.4219 What definitions apply to this subpart?

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

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control

power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016]

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)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011 +	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010 +[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +	4.0 (3.0)		0.20 (0.15)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
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:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, 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.

Each	Complying with the requirement to	You must	Using	According to the following requirements
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(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	(2) Method 4 of 40 CFR part 60, appendix A-3, 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; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, 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.
	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-1	(a) Sampling sites must be located at the inlet and outlet of the control device.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(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-3	(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-1	(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;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(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-3	(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.

[79 FR 11251, Feb. 27, 2014]

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.

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§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	

Attachment G

Federally Enforceable State Operating Permit (FESOP) No: F089-44042-00660

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Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

WHAT THIS SUBPART COVERS

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

§63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

EMISSION AND OPERATING LIMITATIONS

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40

CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013, as amended at 85 FR 78463, Dec. 4, 2020]

General Compliance Requirements

§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad \text{(Eq. 1)}$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 \ F_d}{F_c} \quad (Eq. 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (Eq. 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq. 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and

outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

CONTINUOUS COMPLIANCE REQUIREMENTS

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on

an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

NOTIFICATIONS, REPORTS, AND RECORDS

§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013; 85 FR 73912, Nov. 19, 2020]

§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes

specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

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

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

OTHER REQUIREMENTS AND INFORMATION

§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of

facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	**You must meet the following operating limitation, except during periods of startup . . .**
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO and O_2 measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] [c] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005)[a] [b] [c] (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formalde-hyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
3. Stationary RICE	a. limit the concentra-tion of formalde-hyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix 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 RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the station-ary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formalde-hyde at the exhaust of the station-ary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the station-ary RICE	(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)[a c], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b]You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	**You must submit a . . .**	**The report must contain . . .**	**You must submit the report . . .**
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or	i. Semiannually according to the requirements in §63.6650(b).
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.9(k)	Electronic reporting procedures	Yes	Only as specified in §63.9(j).
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013; 85 FR 73912, Nov. 19, 2020]

Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days,

repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) "Development of an Electrochemical Cell Emission Analyzer Test Protocol", Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) "Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers", EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) "ICAC Test Protocol for Periodic Monitoring", EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) "Code of Federal Regulations", Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility_____ Engine I.D._____ Date_____											
Run Type:	(_)				(_)				(_)		(_)
(X)	Pre-Sample Calibration				Stack Gas Sample				Post-Sample Cal. Check		Repeatability Check
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											

Facility_____ Engine I.D._____ Date_____											
Measurement Data Phase											
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[78 FR 6721, Jan. 30, 2013]

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a New Source Construction and Federally Enforceable State Operating Permit (FESOP)

Source Background and Description

Source Name:	Fulcrum Centerpoint, LLC
Source Location:	6200 Industrial Highway, Gary, Indiana 46406
County:	Lake (Calumet)
SIC Code:	2999 (Products of Petroleum and Coal, Not Elsewhere Classified)
Operation Permit No.:	F089-44042-00660
Permit Reviewer:	Andrew Belt

On March 31, 2022, IDEM, Office of Air Quality (OAQ) posted a notice on IDEM's website (https://www.in.gov/idem/public-notices/), stating that Fulcrum Centerpoint, LLC (herein referred to as "Fulcrum" or "Fulcrum Centerpoint"), had applied for a New Source Construction and FESOP to construct and operate a new stationary biorefinery. The notice also stated that IDEM, OAQ proposed to issue a New Source Construction and FESOP for this operation and provided information on how the public could review the proposed 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 permit should be issued as proposed.

On March 31, 2022, IDEM, OAQ also posted a notice on IDEM's website (https://www.in.gov/idem/public-notices/), stating that IDEM, OAQ would hold a public hearing on April 27, 2022, to discuss the draft New Source Construction and FESOP for Fulcrum Centerpoint, LLC. The notice provided information on how the public could attend the public hearing and how the public could review and provide comments on the proposed permit and other documentation. Finally, the notice informed interested parties that the public notice period would end on Monday, May 2, 2022.

On April 27, 2022, IDEM, OAQ conducted a public hearing regarding the draft New Source Construction and FESOP.

On May 2, 2022, IDEM, OAQ had a notice posted on IDEM's website (https://www.in.gov/idem/public-notices/) informing interested parties that the public notice period was extended an additional 14 days and would end on Monday, May 16, 2022.

IDEM, OAQ thanks all of the commenters and attendees at the public hearing for their interest in the proposed permit renewal and their participation in the permit review process.

The Technical Support Document (TSD) is used by IDEM, OAQ for historical purposes. IDEM, OAQ does not make any changes to the original TSD, but the permit will have the updated changes. The comments and revised permit language are provided below with deleted language as ~~strikeouts~~ and new language **bolded**.

List of ATSD Appendices

This ATSD contains the following appendices:

- Appendix A: Potential to Emit Calculations
- Appendix B: Proposed Changes to Permit.
- Appendix C: Public Hearing Statements and IDEM Responses.

Public Hearing Statements and IDEM Responses

Statements made by the public hearing attendees and IDEM responses are included as Appendix C to this ATSD. The IDEM responses in Appendix C refer back to the General Statements and IDEM Responses section below.

General Statements and IDEM Responses

General Statement 1 - Issuance of the Permit

Many commenters expressed opposition to issuing the permit.

IDEM Response to General Statement 1 - Issuance of the Permit

IDEM's Air Pollution Permitting Program

IDEM's mission is to implement federal and state regulations to protect human health and the environment while allowing for environmentally sound operations of industrial, agricultural, commercial, and government activities vital to a prosperous economy.

IDEM, OAQ issues air pollution permits to facilities that emit regulated levels of pollutants to the air. Permits require sources to comply with all health-based and technology-based standards established by the U.S. Environmental Protection Agency (EPA) and the Indiana Environmental Rules Board. Permit decisions made by IDEM, OAQ are based on the ability of a source to comply with air permit requirements and applicable state and federal air quality rules and regulations.

326 IAC 2-1.1-8, IDEM is required to approve or deny an application received by the department. IDEM, may deny a permit for any of the following reasons:

- An application is deemed to be incomplete after reviewing an applicant's response to a second or subsequent request for additional information. [326 IAC 2-1.1-8(h)]
- The department may deny a permit application because it contains provisions that are not consistent with applicable rules or laws. [326 IAC 2-1.1-8(k)]
- A permit may be denied by the commissioner on the basis of adverse comment if the comment demonstrates the following: (A) The ambient air quality standards under 326 IAC 1-3 cannot be attained or maintained if a permit is issued. (B) The prevention of significant deterioration requirements under 326 IAC 2-2 will not be met. (C) The offset requirements under 326 IAC 2-3 will not be satisfied. (D) For any other reason such as, but not limited to, interference with attainment and maintenance of the standards under 326 IAC 12. [326 IAC 2-8-13(c)(7)]

The proposed permit contains all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board (ERB), which will limit the amount of emissions from the facility to the very lowest level allowed by law. IDEM, OAQ has no authority to create any permit limits or measures that exceed what is legally required for a regulated source.

The information provided by the applicant in an air permit application indicates that that the Permittee will be able to comply with all permit requirements; therefore, IDEM will issue the permit.

This proposed permit is protective of human health and the environment and will allow for environmentally sound operations that may support a prosperous economy.

IDEM, OAQ handles all air permit applications on an objective, consistent, and impartial basis. IDEM, OAQ staff are expected to comply with all applicable state ethics rules and policies. They strive to draft air permit documents and associated calculations/analyses that are thorough, accurate, and that contain all applicable state and federal requirements. All permit limitations are federally enforceable as a practical matter and protective of human health and the environment.

All of Indiana's air pollution control rules are contained in Title 326 of the Indiana Administrative Code, which is available at http://www.in.gov/legislative/iac/iac_title?iact=326 on the Internet. The Indiana air permitting requirements that are applicable to this source are part of the state implementation plan (SIP) that is approved by EPA. Environmental laws are enacted by the Indiana legislature and the legislature has delegated rulemaking authority to the Indiana Environmental Rules Board (ERB). For information on how to get involved in Indiana's Environmental Rulemaking Process, please go to https://www.in.gov/idem/legal/rulemaking/ on IDEM's website.

General Statement 2 - Environmental Justice and Civil Rights Concerns

Several commenters and the U.S. EPA expressed that the proposed facility location would be located in an environmental justice community and that there are environmental justice and civil rights concerns.

IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns

The Indiana Department of Environmental Management, Office of Air Quality (IDEM, OAQ) acknowledges that commenters and the U.S. Environmental Protection Agency (EPA) have concerns about the proposed location of the facility with respect to environmental justice and civil rights. As stated on EPA's Environmental Justice website[1], environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This goal will be achieved when everyone enjoys:

> The same degree of protection from environmental and health hazards, and
> Equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

As stated on U.S. EPA's Title VI and Environmental Justice website[2], and in accordance with Title VI of the Civil Rights Act of 1964[3], each Federal agency shall ensure that all programs or activities receiving Federal financial assistance that affect human health or the environment do not directly, or through contractual or other arrangements, use criteria, methods, or practices that discriminate on the basis of race, color, or national origin.

1 https://www.epa.gov/environmentaljustice
2 https://www.epa.gov/environmentaljustice/title-vi-and-environmental-justice
3 42 U.S.C. § 2000d, *et seq*

I. IDEM Obligations Under Title VI

Title VI of the Civil Rights Act of 1964, prohibits discrimination based on race, color, or national origin in state agency programs that receive federal funding. EPA issued regulations to implement Title VI, codified at 40 C.F.R. section 7.10, *et seq.* The regulations apply to all applicants for, and recipients of, EPA assistance in the operation of programs or activities receiving such assistance as of February 13, 1984.[4] A recipient as defined by the regulations includes IDEM.[5] The regulations state that no person shall be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity receiving EPA assistance on the basis of race, color, national origin, or on the basis of sex in any program or activity receiving EPA assistance under the Federal Water Pollution Control Act, as amended, including the Environmental Financing Act of 1972.[6] The regulations also include specific prohibitions:

> (a) As to any program or activity receiving EPA assistance, a recipient shall not directly or through contractual, licensing, or other arrangements on the basis of race, color, national origin or, if applicable, sex:
> (1) Deny a person any service, aid or other benefit of the program or activity; (2) Provide a person any service, aid or other benefit that is different, or is provided differently from that provided to others under the program or activity; (3) Restrict a person in any way in the enjoyment of any advantage or privilege enjoyed by others receiving any service, aid, or benefit provided by the program or activity; (4) Subject a person to segregation in any manner or separate treatment in any way related to receiving services or benefits under the program or activity; (5) Deny a person or any group of persons the opportunity to participate as members of any planning or advisory body which is an integral part of the program or activity, such as a local sanitation board or sewer authority; (6) Discriminate in employment on the basis of sex in any program or activity subject to section 13, or on the basis of race, color, or national origin in any program or activity whose purpose is to create employment; or, by means of employment discrimination, deny intended beneficiaries the benefits of EPA assistance, or subject the beneficiaries to prohibited discrimination. (7) In administering a program or activity receiving Federal financial assistance in which the recipient has previously discriminated on the basis of race, color, sex, or national origin, the recipient shall take affirmative action to provide remedies to those who have been injured by the discrimination.
> (b) A recipient shall not use criteria or methods of administering its program or activity which have the effect of subjecting individuals to discrimination because of their race, color, national origin, or sex, or have the effect of defeating or substantially impairing accomplishment of the objectives of the program or activity with respect to individuals of a particular race, color, national origin, or sex.
> (c) A recipient shall not choose a site or location of a facility that has the purpose or effect of excluding individuals from, denying them the benefits of, or subjecting them to discrimination under any program or activity to which this part applies on the grounds of race, color, or national origin or sex; or with the purpose or effect of defeating or substantially impairing the accomplishment of the objectives of this subpart.
> (d) The specific prohibitions of discrimination enumerated above do not limit the general prohibition of § 7.30.[7]

4 40 C.F.R. § 7.10, *et seq.*
5 40 C.F.R. § 7.25
6 40 C.F.R. § 7.30
7 40 C.F.R. § 7.35

There is no doubt that the above regulations and Title VI prohibitions apply to permitting decisions by recipients, such as IDEM.[8]

II. IDEM Actions Taken to Prevent Against Discrimination

IDEM's mission is to implement federal and state regulations to protect human health and the environment while allowing the environmentally sound operations of industrial, agricultural, commercial, and governmental activities vital to a prosperous economy.

The Indiana air permitting requirements that are applicable to this source are part of the state implementation plan (SIP) that is approved by EPA. Environmental laws are enacted by the Indiana legislature and the legislature has delegated rulemaking authority to the Indiana Environmental Rules Board (ERB)[9]. IDEM, OAQ has no authority to create any permit limits or measures that exceed what is legally required for a regulated source. Nothing in the criteria, methods, or practices of IDEM, OAQ discriminate based on race, color, or national origin. Permit decisions made by IDEM, OAQ are based on the ability of a source to comply with air permit requirements and applicable state and federal air quality rules and regulations that are in place to protect human health and the environment.

A. IDEM's Nondiscrimination Policy and Environmental Stakeholder Inclusion Program

As part of the IDEM's Nondiscrimination Policy, A-008-AW-18-P-R5, the agency adopted the concept of Environmental Stakeholder Inclusion (ESI) for the fair treatment and meaningful involvement of all people regardless of race, color, gender, national origin, geographic location, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies[10]. An environmental stakeholder is a person with an interest or concern in environmental activities. The intent of IDEM's ESI program is to ensure that interested stakeholders are included and represented in agency actions, as outlined in the agency's Nondiscrimination Policy. Within IDEM, the environmental stakeholder inclusion coordinator works with the agency's program areas to enhance environmental stakeholder involvement in the regulatory processes administered by the agency[11].

B. Public Participation in Permitting Process

IDEM, OAQ encourages the public to participate in the rulemaking and permitting processes. IDEM, OAQ issues notices to the public when citizen participation is required or sought concerning agency actions. Examples include projects requiring an environmental permit, rules being considered by the ERB, and environmental studies or reports available for public comment[12].

To further IDEM, OAQ's commitment to the fair, equitable, and transparent implementation of its Title VI obligations and interactions with the public, IDEM, OAQ implemented the following recommended best practices identified in U.S. EPA's "Plan EJ

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8 40 C.F.R. § 7.35(c); *see also S. Camden Citizens in Action v. N.J. Dep't of Envtl. Prot.,* 145 F. Supp. 2d 446, 476 (D. N.J. 2001)
9 More information about the rulemaking process is available at https://www.in.gov/idem/legal/rulemaking/ on IDEM's Website.
10 IDEM's Nondiscrimination Policy can be found at the following website: https://www.in.gov/idem/health/files/idem_policy_A-008-AW-18-P-R5.pdf
11 Additional information on the IDEM's Environmental Stakeholder Inclusion program can be found at the following website: https://www.in.gov/idem/health/environmental-stakeholder-inclusion/
12 Additional information about public participation in agency actions can be found in the Citizens' Guide to IDEM, which can be found on the following website: https://www.in.gov/idem/resources/citizens-guide-to-idem/

2014" (September 2011)[13] document under section entitled "Considering Environmental Justice in Permitting":

- Public notifications outside of newspapers.
- Direct and targeted outreach to community organizations and institutions.
- Making documents physically accessible and free to communities.
- Scheduling meetings during non-working hours.
- Permit process descriptions of when, where, and how the public can get involved.

IDEM, OAQ also maintains a searchable electronic database for all air permits and permit applications. This database also includes the deadlines for public comments and the schedule of public hearings. IDEM also maintains a searchable electronic database for public access to digital copies of documents through IDEM's Virtual File Cabinet (VFC).

Below is summary of the public involvement and communication for this permitting action:

- A copy of the New Source Construction and FESOP application and the draft New Source Construction and FESOP were physically accessible and free to communities, as follows:
    - A copy of the New Source Construction and FESOP application and the draft New Source Construction and FESOP were sent to the Gary Public Library and Cultural Center, 220 West 5th Avenue in Gary, IN 46402, and IDEM Northwest Regional Office, 330 W. US Highway 30, Suites E & F, Valparaiso, IN 46385 for public review.
    - An electronic copy of the draft permit was made available for public review or download on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/
    - An electronic copy of the permit application and draft permit were also made available via IDEM's Virtual File Cabinet (VFC) for public review or download on the Internet at: https://vfc.idem.in.gov/DocumentSearch.aspx.

- During 2021 and 2022, Fulcrum encouraged open conversation and dialogue with the public and community groups. Fulcrum conducted an extensive community outreach program in partnership with the City of Gary and has committed to continued community outreach sessions throughout 2022. To date, this has included the following:
    - November 3, 2021 – Public Informational Meeting (virtual via Zoom). A notice was posted as early as October 22, 2021, of this meeting by the Gary Redevelopment Commission inviting residents of Gary, Indiana, and all other interested persons. The purpose of this meeting was for Fulcrum to present information on its project and to hear all persons interested in the proposed proceedings. Following the meeting, the City of Gary's Environmental Affairs Department posted on its website (https://gary.gov/environmental-affairs/) Fulcrum's November 3, 2021 presentation, Frequently Asked Questions (FAQs) and Fulcrum's follow-up answers to questions posed.
    - November 16, 2021 – Gary Common Council Meeting and Approval of the Project
    - Development Agreement with the City of Gary
    - December 15, 2021 – Community Open House (in-person)
    - December 21, 2021 – Fulcrum Response to Gary Advocates for Responsible Development (GARD) Questions were posted to the Fulcrum Centerpoint project website (https://centerpoint.fulcrum-bioenergy.com)

13 https://nepis.epa.gov/Exe/ZyPDF.cgi/P100DFCQ.PDF?Dockey=P100DFCQ.PDF

- January 26, 2022 – Community Open House (virtual via Zoom). The community was concerned that not all interested citizens participated in the in-person Community Open House held on December 15, 2021, due to COVID-19. In response to this community concern, Fulcrum followed up with a January 26, 2022, Community Open House via Zoom.
- March 29, 2022 – Community Informational Meeting. Fulcrum participated in a livestreamed community informational meeting at J's Breakfast Club ('A Seat at the Table' event). The purpose of this community informational meeting was for Fulcrum, city leaders, and community leaders to provide information and discussion to local residents about economic development and redevelopment in the City of Gary and Fulcrum's proposed biorefinery.
- June 14, 2022 – Public Informational Meeting and Site Tour. The purpose of this free public meeting was for Fulcrum to present a one-hour presentation about the company and its innovative approach to waste reduction and renewable fuels and to provide a bus tour of the proposed biorefinery site to residents, business leaders, and political leaders.
- Prompt responses to questions received from residents and community groups

During the public meetings, Fulcrum provided updates on the project, its permitting, and the status of the Sierra operations. Further, Fulcrum encouraged questions and requested ideas for betterment of the community. Fulcrum has stated it is committed to continuing to hold public meetings.

To aid with project visibility in the community, Fulcrum developed a project website (https://centerpoint.fulcrum-bioenergy.com) which provides the public with extensive information on the project, including a project overview, how it works (it being the innovative process that transforms municipal solid waste (MSW) into sustainable aviation fuel (SAF), environmental impact, employment opportunities, and anticipated timeline. In addition, the website has a section dedicated to and entitled, Community Resources, where material and information provided during community outreach sessions, responses to Frequently Asked Questions (FAQs), responses to specific questions received from residents and/or community groups, and news may be found. Further, the Project Director's contact information is provided.

In addition to community outreach, Fulcrum continued to engage local government officials and stay active in local chamber events. Fulcrum has stated that it is committed to academics/education and engaging other stakeholders working toward creating a sustainable community while enhancing its economic development. To date, Fulcrum has made several commitments for the benefit of Gary and its residents. This includes:

- A $10 million tax increment financing (TIF) bond, which will be purchased by Fulcrum. The City of Gary will use the proceeds to demolish abandoned and blighted buildings across the city.
- A commitment to prioritize the hiring of Gary residents and Gary-based businesses.
- A commitment to ensure appropriate technical training is available through local colleges, so Gary residents and its high school graduates possess the necessary skills for job opportunities at Fulcrum Centerpoint. Fulcrum has started engagement and development of training plans with Ivy Tech Community College. In addition, Fulcrum Centerpoint will have its own apprenticeship program for certain positions at its feedstock processing facilities.
- A commitment to Shirley Heinze Land Trust for a donation to support a capital improvement project for the Ivanhoe South Nature Preserve on the west side of Gary. Ivanhoe South preserves and protects Dune and Swale habitat.

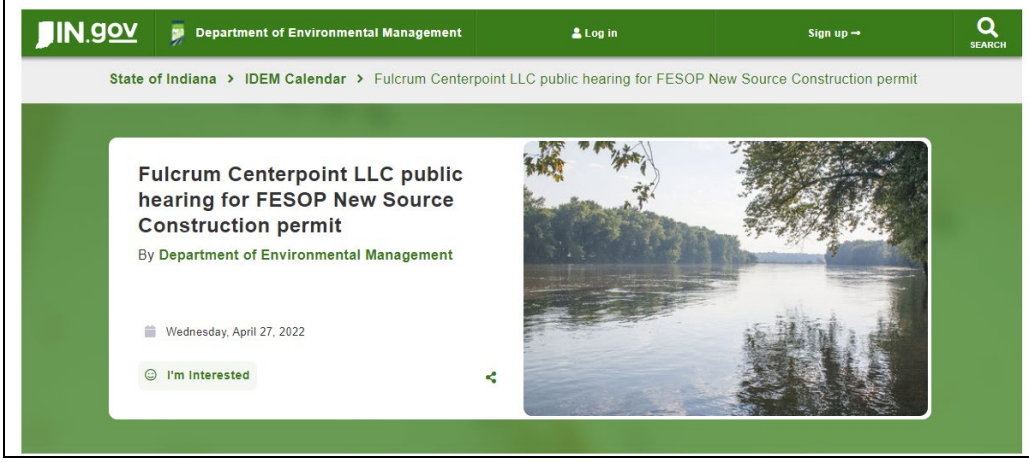
Fulcrum has stated that it continues to explore opportunities to support community organizations, parks, and greenspaces in the City of Gary. Fulcrum continues to solicit ideas from the community to support parks and greenspaces, including at the latest Community Open House on January 26, 2022. As plans develop, these will be shared with the community and announced on the Fulcrum Centerpoint website over the course of 2022.

- On March 31, 2022, IDEM, OAQ posted a notice on IDEM's website (https://www.in.gov/idem/public-notices/), stating that Fulcrum Centerpoint, LLC, had applied for a New Source Construction and FESOP to construct and operate a new stationary biorefinery. The notice also stated that IDEM, OAQ proposed to issue a New Source Construction and FESOP for this operation and provided information on how the public could review and provide comments on the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether this permit should be issued as proposed. The notice provided the permit writer's name and direct contact information and specified that written comments could be submitted in hardcopy by U.S. mail, private carrier, in person, or electronically by e-mail or fax.

- On March 31, 2022, IDEM, OAQ also posted a notice on IDEM's website (https://www.in.gov/idem/public-notices/), stating that IDEM, OAQ would hold a public hearing on April 27, 2022, to discuss the draft New Source Construction and FESOP for Fulcrum Centerpoint, LLC. The notice provided information on how the public could attend the public hearing, provided information for citizens that needed reasonable accommodations to participate in this event, including accommodations for persons with speech or hearing difficulties, and how the public could review and provide comments on the proposed permit and other documentation. Finally, the notice informed interested parties that the public notice period would end on Monday, May 2, 2022.

  Information regarding the public hearing was posted to the IDEM Calendar Events website (https://events.in.gov/idem). Below is a screenshot of the calendar event for the Fulcrum Centerpoint public hearing.

https://events.in.gov/event/fulcrum_centerpoint_llc_public_hearing_for_fesop_new_source_construction_permit



ABOUT THIS EVENT

21st Century Charter School of Gary, Gymnasium | View map | Add to calendar

556 Washington Street, Gary, IN 46402

The Indiana Department of Environmental Management (IDEM) will hold a public hearing to allow for testimony regarding the draft new source construction and Federally Enforceable State Operating Permit (FESOP). IDEM's Office of Air Quality (OAQ) will hold this public hearing at the following time and location:

Wednesday, April 27, 2022
Start time: 5:30pm (CDT)
21st Century Charter School of Gary – Gymnasium
556 Washington Street
Gary, Indiana 46402

IDEM, OAQ will not provide responses to questions or comments made during the hearing. The purpose of the hearing is to allow for the public to provide testimony. IDEM will provide responses to all comments made during the hearing, along with all other written comments provided to the agency during the public comment period, as part of the response to comment in the final permit.

Written comments and supporting documentation can be presented at the public hearing, or if you do not plan to attend this hearing, you can send written comments to IDEM before the end of the public notice period.

The public notice period has been extended to Monday, May 2, 2022. All comments will be considered by IDEM when we make a decision to issue or deny the permit.

If you do not want to comment, but would like to be added to IDEM's mailing list to receive notice of future action related to this permit application, please contact IDEM. Please refer to permit number F089-44042-00660 in all correspondence.

To Contact IDEM:
Andrew Belt
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: (800) 451-6027, ask for Andrew Belt
or (317) 232-3217
Email: abelt@idem.IN.gov

If you need reasonable accommodations to participate in the public hearing, please contact IDEM's Americans with Disabilities Act coordinator at: Indiana Department of Environmental Management Attn: ADA Coordinator 100 North Senate Avenue Indianapolis, IN 46204-2251 317-233-4200 Please provide a minimum of 24 hours notice if possible. Speech and hearing impaired callers may contact the agency via the Indiana Relay Service at 1-800-743-3333.

EVENT DETAILS

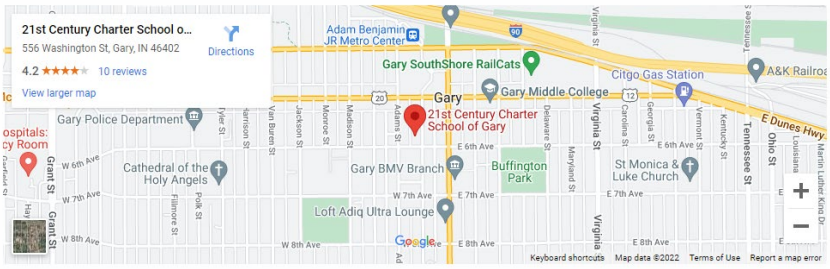
EVENT TYPE
PUBLIC NOTICES | EVENTS

CALENDAR
AGENCY | IDEM

GROUP
Department of Environmental Management

CONTACT NAME
Andrew Belt
CONTACT PHONE
(317) 232-3217
CONTACT EMAIL
Email: abelt@idem.IN.gov

Hide map | Public transport | Car | Walking



- IDEM, OAQ sent the above notifications to all persons and entities (e.g., consultants, companies/corporations, groups, organizations, etc.) on the interested parties mailing list who had requested in writing to be on the list. The interested parties list included 16 persons or entities.

- IDEM, OAQ also sent the above notifications to the following local government officials:

  (1) Gary City Health Department, 1145 W 5th Ave, Gary, IN 46402
  (2) Lake County Commissioners, 2293 N. Main St, Building A 3rd Floor, Crown Point, IN 46307
  (3) Gary City Council, 401 Broadway #209, Gary, IN 46402
  (4) City of Gary Dept. of Environmental Affairs, 401 Broadway, Suite 304, Gary, IN 46402
  (5) Lake County Health Department, 2900 W 93rd Ave, Crown Point, IN 46307
  (6) City of Gary Redevelopment Commission, 839 Broadway, Gary, IN 46402

- IDEM typically posts a weekly submission to its Twitter site (https://twitter.com/idemnews), Facebook site (https://www.facebook.com/IndDEM), Instagram site (https://www.instagram.com/idemnews), and LinkedIn site (https://www.linkedin.com/company/inddem) indicating the number of new or updated IDEM public notices that have been posted to its website in the last week and providing a link for the public to view public notices and to sign up for IDEM public notice notifications (https://on.in.gov/publicnotices)

- On April 27, 2022, at 5:30 p.m. Central Time, IDEM, OAQ began a public hearing regarding the draft New Source Construction and FESOP for Fulcrum Centerpoint, LLC. After several requests for additional testimony and receiving no responses, the public hearing was concluded at 7:10 p.m. Central Time. The public hearing was well attended and received coverage from local television and newspapers.

- IDEM further extended the public comment period on the draft New Source Construction and FESOP an additional 14 days. On May 2, 2022, IDEM, OAQ posted a notice on IDEM's website (https://www.in.gov/idem/public-notices) informing interested parties that the public notice period was extended an additional 14 days and would end on Monday, May 16, 2022.

All written comments submitted to IDEM, OAQ during the public comment period and all verbal statements received during the public hearing were reviewed and detailed responses to those comments and statements are provided in this Addendum to the Technical Support Document (ATSD) and associated appendices.

IDEM, OAQ believes that it has taken all reasonable steps to ensure that all persons, regardless of race, color, or national origin or sex, have had a full and fair opportunity to participate in this permitting decision. Additionally, IDEM, OAQ believes that it has complied with the requirements of Title VI and EPA's implementing regulations. This is evidenced by the significant public participation throughout all stages of this permitting process.

IDEM, OAQ recognizes and understand the concerns expressed through public comments and during the public hearing regarding environmental justice concerns. A review of EPA EJ Screen shows that the area within a 5-mile radius of the proposed site generally falls within the 75th percentile for the environmental and socioeconomic indexes examined the EJ Screen tool. However, IDEM, OAQ cannot resolve the historical issues that lead to the development of the area through an individual permitting

decision. IDEM, OAQ believes that these concerns can be balanced with IDEM, OAQ's commitment to public involvement in the permitting process to ensure all people have an equitable opportunity to participate in the permitting decision, as well as IDEM OAQ's obligation to regulate emissions and enforce permit conditions. The proposed permit contains all health-based and technology-based standards established by EPA and the ERB, which will limit the amount of emissions from the facility to the very lowest level allowed by law. Additionally, please see IDEM Response to General Statement 7 for a detailed discussion of the relevant National Ambient Air Quality Standards for this permit and area. IDEM, OAQ believes that these enforceable limits are sufficient to protect public health and the environment.

General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads

Many commenters expressed concern regarding the additional truck traffic, mobile (diesel tailpipe) emissions, vehicle noise, roadway impacts (roadway degradation), and fugitive dust (particulate matter) emissions associated with the truck traffic (dirt, dust, debris, and spillage).

IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads

IDEM, OAQ recognizes that construction and operation of an industrial facility can raise public concerns about potential negative impacts with respect to additional truck traffic, mobile (diesel tailpipe) emissions, vehicle noise, roadway impacts (roadway degradation), and fugitive dust (particulate matter) emissions associated with the truck traffic on offsite public roads (dirt, dust, debris, and spillage).

Truck Traffic, Vehicle Noise, Roadway Impacts

With respect to additional truck traffic, vehicle noise, and roadway impacts (roadway degradation), IDEM, OAQ does not have the authority to evaluate these types of issues as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues.

Mobile Source (Tailpipe) Emissions

With respect to air pollution that is emitted from fuel combustion in a "mobile source" (i.e., tailpipe emissions from vehicles), IDEM, OAQ does not have the authority to evaluate these types of issues as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues.

For air permits, "mobile sources" are excluded from the definition of "source" under Title 326 of the Indiana Administrative Code (IAC) 326 IAC 1-2-73; therefore, mobile source emissions (fuel combustion tailpipe emissions from vehicles) not included in the potential to emit (PTE) of a source. The definition of "source" is provided below.

> 326 IAC 1-2-73 "Source" defined
> An aggregation of one (1) or more stationary emissions units that are located on one (1) piece of property or on contiguous or adjacent properties are owned or operated by the same person (or by persons under common control) and belong to a single major industrial grouping. For purposes of defining a source, two (2) or more contiguous or adjacent properties shall be considered part of a single major industrial grouping if all of the pollutant emitting activities at such contiguous or adjacent properties belong to the same major group, that is, all have the same two (2) digit Standard Industrial Classification (SIC) code as described in the Standard Industrial Classification Manual,

> 1987. Any stationary source (or group of stationary sources) that supports another source, where both are under common control of the same person (or persons under common control) and are located on contiguous or adjacent properties, shall be considered a support facility and part of the same source regardless of the two (2) digit SIC code for that support facility. A stationary source (or group of stationary sources) is considered a support facility to a source if at least fifty percent (50%) of the output of the support facility is dedicated to the source. ***A source does not include mobile sources, nonroad engines, or nonroad vehicles. (emphasis added)***

Regarding comments about quantifying the impact of tailpipe emissions, IDEM, OAQ used the U.S. EPA Diesel Emission Quantifier (DEQ) to determine the impact of tailpipe emissions from the truck traffic traveling to and from the Fulcrum Centerpoint property.

The projected tailpipe emissions are:

- 0.86 tons NOx per year
- 0.016 tons VOC per year
- 0.001 tons PM2.5(direct) per year

The projected percent increase in <u>mobile source</u> emissions in Lake County are as follows:

- 0.006% NOx
- 0.002% VOC
- 0.00003% PM2.5 (direct)

The projected increases do not take into account existing emissions from stationary sources. If existing stationary source emissions were taken into account, the percent increase in VOC, NOx, and PM2.5 emissions in Lake County would be substantially less.

IDEM, OAQ does not have legal authority to require that diesel fueled delivery trucks be equipped with the latest tailpipe exhaust emissions control technologies, such as diesel particulate filters with NOx reduction systems such as Selective Catalytic Reduction (SCR).

<u>Fugitive Dust from Truck Traffic on Offsite Roads</u>

With respect to fugitive dust (particulate matter) emissions from truck traffic on offsite public roads that are outside of the Fulcrum Centerpoint property, IDEM, OAQ does not have the authority to evaluate these types of issues as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues. However, local city code includes requirements to address these issues.

The City of Gary, Zoning Department, issued a zoning verification letter to Fulcrum Centerpoint, LLC (see VFC document #83302394, pages 92-125 of 184), specifying that the biorefinery operation would be required to comply with the City of Gary Municipal Code (MC), Chapter 34 (Solid Waste), which can be found on the internet at:
https://library.municode.com/in/gary/codes/code_of_ordinances?nodeId=PTIGEOR_CH34SOWA_ARTIILICO

Under the City of Gary Municipal Code, Chapter 34, Article II (Litter Control), Section 34-24, no person shall drive or move any truck or other vehicle within the city unless the vehicle is so constructed or loaded as to prevent any load, contents, or litter from being blown or deposited upon any street, alley, or other public place.

Fulcrum Centerpoint, LLC, provided a Site Operating Plan (SOP) in its solid waste processing permit application (see VFC document # 83257441) that indicated that feedstock will be delivered to the facility by trucks with enclosed trailers, which will prevent the escape or spillage of feedstock during transport.

Fugitive dust (particulate matter) emissions from truck traffic on onsite paved roads and parking lots on the Fulcrum Centerpoint property are included as part of the source-wide air pollution emissions and are regulated in the air permit and the Fugitive Dust Control Plan (FDCP).

General Statement 4 - Fugitive Dust and Particulate Matter

Many commenters expressed concern regarding the potential fugitive dust (particulate matter) emissions from truck traffic on onsite roads and fugitive dust escaping from the feedstock storage building (e.g., truck entry/exit doorways).

IDEM Response to General Statement 4 - Fugitive Dust and Particulate Matter

IDEM, OAQ recognizes that potential fugitive dust (particulate matter) emissions from truck traffic on onsite roads and fugitive dust escaping from the feedstock storage building (e.g., truck entry/exit doorways) are of great concern to the commenters and other local residents.

The potential to emit (PTE) air pollution for the Fulcrum Centerpoint source was summarized in the Technical Support Document (TSD) for the draft permit and the PTE calculations were included in Appendix A of TSD. The TSD was part of the permit documents provided during the public notice period and is available at https://permits.air.idem.in.gov/44042d.pdf on IDEM's website.

The TSD (page 7) includes a PTE table labeled "Unrestricted Potential Emissions (ton/year)" and shows the maximum amount of each regulated air emission that the source could potentially emit if it operated 24 hours a day, 365 days a year (8,760 hours per year), without any permit limitations or pollution controls. The TSD (page 8) includes a PTE table labeled "PTE of the Entire Source After Issuance of FESOP (tons/year)" and shows limited emissions after issuance of the permit, based on all permit limitations. Please refer to the TSD for more extensive information regarding these emissions. Since all stockpiled feedstock material will be kept in enclosed buildings/structures and all feedstock material conveyance systems will be enclosed, the amount of fugitive dust that escapes from the feedstock storage building (e.g., truck entry/exit doorways) is expected to be minimal.

The permit includes the following requirements related to fugitive dust, opacity, and particulate matter emissions:

- Permit Section C.2 (Opacity) requires the source to comply with the opacity limits under 326 IAC 5-1-2.
- Permit Section C.5 (Fugitive Dust Emissions) prohibits the Permittee from allowing 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 Indiana Administrative Code (IAC) 6-4.
- Permit Section C.6 (Fugitive Dust Emissions) (added to the permit in IDEM Response to U.S. EPA Comment 2) requires the source to comply with the fugitive particulate matter, visible emission, and opacity limits and requirements under 326 IAC 6.8-10-3 and to control fugitive particulate matter emissions according to the Fugitive Dust Control Plan that is included as Attachment A to the operating permit.
- Sections D.1 contains applicable particulate matter (PM/PM10/PM2.5) limitations and standards for various emissions units. These sections also contain any applicable control device operating requirements, monitoring requirements, testing requirements, and associated record keeping and reporting requirements to assure that all permit limitations are enforceable as a practical matter and to assure that the source can demonstrate compliance with all applicable state and federal rules on a continuous basis. For a summary of the pollution control, compliance determination, compliance monitoring, and

stack testing requirements contained in the proposed permit, see IDEM Response to General Statement 9 - Pollution Control, Compliance Determination/Monitoring, and Stack Testing.

- Attachment A of the permit includes a Fugitive Dust Control Plan (FDCP). As part of the FDCP, dust control measures shall be performed as necessary, including requiring that delivery and shipping trucks adhere to a posted facility speed limit of 20 miles per hour, vacuum sweeping, flushing, and/or wet power brooming of paved roads and parking lots, maintenance of the roadway surface and application of chemical dust suppressant(s) as necessary, requiring that Feedstock will be unloaded in one (1) of the three (3) separate Feedstock storage buildings, which are each enclosed with solid walls and doors that will be closed when the facility is not in operation or when feedstock deliveries are not being made, minimizing the footprint of any areas of land disturbance(s) and the reestablishment of natural foliage cover, controlling fugitive dust from any disturbed land(s) using water, chemical dust suppressants, berms, wind fences and/or boundary fencing, and controlling fugitive dust from any unnecessarily disturbed land(s) using landscaping and/or re-seeding. Additionally, the FDCP contains requirements for visual monitoring, recordkeeping, and an employee/contractor training program. Please see the Attachment A of the permit for the entire Fugitive Dust Control Plan (FDCP).

As part of IDEM Response to U.S. EPA Comment 2, the Fugitive Dust Control Plan is revised to include addition requirements and information and to clarify existing requirements. See IDEM Response to U.S. EPA Comment 2.

If residents witness or have evidence of noncompliance with the FDCP, residents can contact the IDEM, OAQ compliance inspector or submit a complaint. For information on contacting the IDEM, OAQ compliance inspector or submitting a complaint, see IDEM Response to General Statement 5 - Possible Future Violations.

Requirements of 326 IAC 6-4 (Fugitive Dust Emissions)

The Permittee (Fulcrum Centerpoint) is required to comply with permit Section C.5 - Fugitive Dust Emissions [326 IAC 6-4], which specifies that the Permittee (Fulcrum Centerpoint) 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). The requirements of 326 IAC 6-4 specify the criteria for determining if a source is in violation of 326 IAC 6-4 and the requirements for fugitive dust measurements or observations.

The measurement for fugitive dust is specified in 326 IAC 6-4-5 (Measurement processes) available at http://iac.iga.in.gov/iac//T03260/A00060.PDF. The rule requires ambient air concentrations to be measured using the standard hi volume sampling and analysis techniques as specified sampling and analysis techniques as specified by 40 Code of Federal Regulations (CFR) 50. Observations by a qualified representative of the Commissioner include at a minimum training and certification in 40 CFR 60, App. A-4, Method 9 Visual Determination of the Opacity of Emissions from Stationary Sources. IDEM compliance inspectors monitor property lines as part of inspections to assure sources are meeting the requirements of the permit including the Fugitive Dust Rule, 326 IAC 6-4.

For sources to comply with fugitive dust rules, prevention measures may be required. However, under 326 IAC 6-4-6 certain activities are exempt from the fugitive dust rule. Common examples include dust from agricultural, construction, or demolition activities providing every reasonable precaution has been taken to minimize dust; as well as dust from publicly maintained unpaved roads where a nuisance or health hazard is not being created. Best practices for preventing fugitive dust include, but are not limited to, applying water or dust suppressants, reducing speed

when driving on unpaved roads and lots, and paving roadway entry and exit paths where possible.

If residents witness or have evidence of noncompliance with the permit Section C.5 - Fugitive Dust Emissions [326 IAC 6-4], residents can contact the IDEM, OAQ compliance inspector or submit a complaint. For information on contacting the IDEM, OAQ compliance inspector or submitting a complaint, see IDEM Response to General Statement 5 - Possible Future Violations.

If it is determined that a source has violated the Fugitive Dust Rule 326 IAC 6-4, IDEM, OAQ will take appropriate action to bring to source back into compliance with applicable permit conditions, state rules, and federal regulations.

The permit does not include a specific frequency for determining compliance with permit Section C.5 - Fugitive Dust Emissions [326 IAC 6-4]. However, Fulcrum Centerpoint is required to comply with permit Section C.5 - Fugitive Dust Emissions [326 IAC 6-4] at all times.

General Statement 5 - Possible Future Violations

Many commenters expressed the permit should not be approved, since the source may have future violations of environmental law.

IDEM Response to General Statement 5 - Possible Future Violations

IDEM, OAQ understands that residents have concern that the source could have possible future violations of environmental law. However, court cases in Indiana support the proposition that an initial permit cannot be denied due to an allegation of possible future violations of environmental law. *See* Talara Lykins - CAFO, 2007 OEA 114, DeGroot Dairy CFO, 2006 OEA 1, Kyle Hall, 2008 OEA 100, which can be found at the following website: https://www.in.gov/oea/2335.htm

Fulcrum Centerpoint is required to comply all air permit requirements and applicable state and federal air quality rules and regulations. If it is determined that Fulcrum Centerpoint has violated a permit term or condition, IDEM, OAQ will take appropriate action to bring to source back into compliance with applicable permit conditions, state rules, and federal regulations.

IDEM, OAQ encourages residents to contact an IDEM, OAQ compliance inspector if they witness or have evidence of any compliance related concerns with this operation. An IDEM, OAQ compliance inspector will investigate complaints, perform any necessary observations or inspections of the source, determine if a violation of a permit term or condition has occurred, take appropriate action when a violation is observed, and initiate any necessary actions to bring to source back into compliance with applicable permit conditions and state and federal rules and regulations. The current compliance inspector for each county in Indiana can be found at the following website: https://www.in.gov/idem/idem-regional-staff-and-inspectors/. The current IDEM, OAQ compliance inspector for the Fulcrum Centerpoint source is Sasa Dunovic, who may be contacted by telephone at (219) 252-3566 or toll free (800) 451-6027 an ask for Sasa Dunovic or by e-mail at sdunovic@idem.in.gov.

If the commenter or citizens have complaints and issues with the source with respect to compliance with its air permit, complaints can be submitted to IDEM three (3) different ways:

1. Online at: https://www.in.gov/idem/contact/file-a-complaint/;
2. Through the Complaint Coordinator at (800) 451-6027 ext. 24464; or
3. By printing, completing, and mailing a paper-based Complaint Submission Form (Available under Agency Forms at: https://www.in.gov/idem/forms/idem-agency-forms/).

IDEM, OAQ and U.S. EPA inspections are unannounced. IDEM, OAQ normally inspects major sources on an annual basis. IDEM, OAQ will make more frequent inspections on a case-by-case basis based on the compliance history of the source and any public complaints received. During an inspection, the IDEM, OAQ inspector will perform a records review, and inspect the facility operations, to determine if the source is in compliance with all air permit terms and conditions. Regular inspections, regular stack testing, along with compliance monitoring, record keeping and reporting, will allow IDEM, OAQ to determine if Fulcrum Centerpoint is in continuous compliance with all air permit terms and conditions. If it is determined that Fulcrum Centerpoint has violated a permit term or condition, IDEM, OAQ will take appropriate action to bring to source back into compliance with applicable permit conditions, state rules, and federal regulations.

IDEM uses a number of enforcement tools to bring sources that are out of compliance with a permit term or condition back into compliance. If it is determined that a source has violated a permit term or condition, IDEM, OAQ will take appropriate action to bring to source back into compliance with applicable permit conditions, state rules, and federal regulations. Most violations of environmental laws are resolved informally. As part of the informal resolution, a “warning letter” or “violation letter” is sent, noting the violation and measures necessary to correct it in order to ensure the responsible party corrects the documented problem. Certain violations are referred directly to formal administrative enforcement and may receive a Notice of Violation (NOV). An NOV normally results in the assessment of civil penalties and the requirement that IDEM and the respondent sign an Agreed Order (AO). The AO ensures that the respondent achieves and maintains compliance with Indiana's environmental statutes and rules. Any civil penalties accessed in an NOV by IDEM, OAQ are determined based on Indiana Code 13-30 and IDEM’s Nonrule Policy Document (NPD) “Civil Penalty Policy” (ENFORCEMENT-99-0002-NPD available at https://www.in.gov/idem/files/nrpd_enf-002.pdf on IDEM’s website.

General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents

Many commenters expressed the source would have a negative impact on the local area for the following reasons (with a summary of the comments provided for each issue):

- Employment - instead of toxic jobs, the city of Gary needs a workforce that is educated, skilled and trained for jobs in a green economy and making a living wage;
- Quality of Life - the source would have a negative effect on the quality of human and environmental life in the local area (lakefront); residents of Gary deserve the opportunity to develop our lakefront to be that of a community that they can enjoy;
- Noise - the source would cause noise pollution.

Many commenters expressed the permit should not be approved for the following reasons (with a summary of the comments provided for each issue):

- Zoning - the source would be located in a highly industrialized, highly polluted, and populated area, Fulcrum should find another location that is safer, that is not so environmentally sensitive, and will still provide economic benefit to the area, the site should be turned into a greenway; the source would be too close to residential/civilization areas, wetlands, wildlife/natural areas and nature preserves, rivers, lakes, recreational areas (including Jeorse Park); please locate the proposed biorefinery in a neighborhood where there are plenty of rich white people and see how it works out there.
- Water Pollution - the source may result in water pollution in local wetlands, rivers, lakes, and drinking water; Lake Michigan is a resource to be protected at all costs; the plant would be located to close to Lake Michigan which is the drinking water source for millions of people in three states;
- Land Pollution - the source may result in land pollution; additional pollution from this facility should not be permitted in the local area, since the area around the proposed site

(Lake County or the city of Gary) already has 52 CERCLA/Superfund sites, 423 hazardous waste sites, and more than 460 underground storage tanks.

- Sustainability Issues - Instead of the Fulcrum Centerpoint biorefinery, the city of Gary needs companies that will recover, reuse and/or recycle waste, and utilize renewable sources of energy (solar, wind, and waves); the city of Gary needs companies that will provide sustainable growth and enhance citizen's lives, the environment, and housing options; If Fulcrum wants to claim that they are sustainable or green, why was Gary identified as a place to haul massive amounts of waste, mainly from Illinois, while the proposed sorting facility is many miles from the gasification plant?; I am concerned that this facility will undermine the work we have done for years with waste reduction and recycling and will encourage us to become even more of a throwaway society; What is the true cost to operate this facility when you factor in the downside to future generations due to the reckless depletion of our resources?;
- Economic/Feasibility Issues - the proposed Fulcrum biorefinery is not economically viable; there are concerns related to the feasibility of the technology; there could be problems associated with transporting materials to the facility, it is not easy to produce jet fuel from Municipal Solid Waste through gasification; please look beyond BP-funded studies to learn about gasification and the Fischer-Tropsch process; citizens have no access to much of the financial data or proprietary information that is important to know; the city of Gary residents want economic development, but we don't want it at the sacrifice of potential health or potential concerns;
- No Proven Track Record - The Fulcrum Sierra BioFuels Plant near Reno, Nevada does not have a documentable track record of safety, effectiveness, and meeting air permit limits, has been non-operational, and has not produced a single gallon of fuel; the proposed operation is unproven, has never been done successfully before on a commercial scale, and is risky; IDEM should place a hold on the permit application (or deny the permit) and require Fulcrum to document a minimum one-year record that they operate their Nevada biorefinery with feedstock and not municipal solid waste to prove that the proposed source will not negatively impact human health and the environment; several Indiana companies have tried this and they have all failed; a proposed Brightmark facility in Macon, Georgia, was dismissed; we should wait to see how well the Fulcrum Nevada plant works, get several months of emissions data for an accurate analysis of air emissions, and require the information as part of the application;
- Accidents (Spills, Leaks, Fires, and Explosions) - the source could have accidents, including spills, leaks, fires, and explosions at the proposed plant; the permit must mandate stringent requirements for proper oversight, maintenance, and replacement of worn-out equipment to prevent pollution and possible explosions; Fulcrum has no comprehensive environmental response plan with first responders in case of any accident, spill, fire or other incident; Are the local level emergency preparedness and response capabilities capable of responding to incidents at this proposed facility?

IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents

Employment, Quality of Life, and Noise

IDEM, OAQ recognizes that construction and operation of an industrial facility can raise concerns about potential negative impacts with respect to employment, quality of life, and noise. However, IDEM, OAQ does not have the authority to evaluate these types of issues as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues.

Prior to construction and operation, Fulcrum Centerpoint will be required to apply for and obtain a solid waste processing permit from IDEM's Office of Land Quality (OLQ). The solid waste

processing rule 329 IAC 11-13.5-7 specifies that "vectors, dust, odors, spills, and noise must be controlled at all times such that there is no nuisance or health hazard at the facility". IDEM, Office of Land Quality (OLQ) routinely inspects sources issued a solid waste processing permit under 326 IAC 11 to assure the requirements of the solid waste processing permit are being met.

Zoning

IDEM, OAQ also understands that residents that live in an area have concerns with the propriety of the zoning. However, IDEM, OAQ does not have the authority to evaluate zoning or other local level permitting requirements as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues. Zoning and other local level permitting decisions are made by local government bodies and officials.

The City of Gary, Zoning Department, zoned the proposed Fulcrum Centerpoint, LLC, biorefinery source location (parcel) with a M3 Heavy Industrial District classification, pursuant to the City of Gary municipal code Sec. 123-219. The zoning determination was for a proposed biorefinery that would process feedstock derived off-site from municipal solid waste ("MSW") and convert it through a catalytic process into low-sulfur jet fuel. For additional information, see VFC document #83302394, pages 92-125 of 184.

Water Pollution and Land Pollution

IDEM, OAQ understands that residents have concern that the source could result in water or land pollution. Fulcrum Centerpoint will be required to obtain any applicable permits from IDEM's Office of Land Quality (OLQ) and Office of Water Quality (OWQ), which will contain all applicable state and federal rules and regulations related to land and water pollution. This proposed air permit only contains applicable state and federal rules and regulations related air pollution.

Fulcrum Centerpoint, LLC, provided the following information in the box below regarding the handling of wastewater and stormwater at the proposed facility on its website (https://centerpoint.fulcrum-bioenergy.com/) under Frequently Asked Questions (FAQs) and several Question and Answer (Q&A) documents:

Excerpts Fulcrum Website Information, FAQs, and Q&A Documents

Centerpoint WILL NOT be directly discharging anything into Lake Michigan or any other water source. All the wastewater from the facility will be treated in an onsite wastewater pre-treatment plant, before being discharged to the Gary Sanitary District's (GSD) wastewater treatment plant for further treatment. The Facility will then receive treated effluent/recycled water from GSD for the process (instead of potable water). This should result in a net decrease in the amount of treated effluent discharged from the GSD treatment plant.

A National Pollution Distribution Elimination System (NPDES) permit is not required for the wastewater discharge under the federal Clean Water Act as the facility's wastewater will be pre-treated on site and then sent via City sewer to the Gary Sanitary District's wastewater treatment plant.

There are approximately 2.3 acres of wetlands on the eastern end of the property, which will not be disturbed. These wetlands are not dune and swale habitat.

The Centerpoint Biorefinery will have a stormwater management plan and a stormwater permit from the City of Gary. Stormwater will be collected in a detention pond on site.

The facility will be regulated and monitored under a number of environmental permits, including an air permit, solid waste permit, wastewater discharge permit (to Gary Sanitary District), storm water permit and City building permits.

Sustainability Issues

IDEM, OAQ understands that some commenters have concerns that the source could undermine waste reduction and recycling achieved by the community. However, IDEM, OAQ does not have the authority to evaluate these types of issues as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues. Additionally, see IDEM's response in the previous subsection entitled "Zoning".

Economic/Feasibility Issues

IDEM, OAQ understands that some commenters have concerns that the source would be economically infeasible. However, IDEM, OAQ does not have the authority to evaluate these types of issues as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues. Regarding technical feasibility comments, see IDEM's response in the next subsection entitled "No Proven Track Record".

No Proven Track Record

IDEM, OAQ understands that many commenters have concerns that the proposed operation is unproven and that the Fulcrum Sierra BioFuels Plant near Reno, Nevada does not have a documentable track record of safety, effectiveness, and meeting air permit limits, and has been non-operational.

Fulcrum Centerpoint, LLC, provided the following information in the box below regarding the biorefinery gasification process and the Fulcrum Sierra BioFuels Plant near Reno, Nevada on its website (https://centerpoint.fulcrum-bioenergy.com/) under Frequently Asked Questions (FAQs) and several Question and Answer (Q&A) documents:

Excerpts Fulcrum Website Information, FAQs, and Q&A Documents

Fulcrum's process uses fully licensed technologies that are commercially proven and have been used around the world for decades in other applications. The gasification process used for Sierra and Centerpoint is licensed from an experienced supplier who has tested the Fulcrum-specific feedstock and provided a performance guarantee for their design. All of the equipment used in the process (gasification, etc.) is commercially proven at scale and each comes with vendor performance guarantees.

Fulcrum's process was demonstrated and proven in 2014 using a process demonstration unit, which demonstrated the process for 120 days continuously. The process demonstration unit was located in Raleigh, NC. It was established to demonstrate and prove the reliability and safety of the process and was operated continuously for 120 days. It was then dissembled following the successful demonstration.

Fulcrum's first commercial facility near Reno, NV - the Sierra BioFuels Plant - is in the process of starting operations and will be fully operational before construction begins on Centerpoint. Operations at Sierra are starting up now and first fuel is expected to be produced by the end of this year (2021). Over the next 12 months, the startup process and the steady ramp up of operations will demonstrate the safety and reliability of the plant. Fulcrum does not expect to finalize design or start construction on Centerpoint until Sierra is fully operational. The Sierra BioFuels Plant was also debt financed in 2017, which raised over $250 million for the

construction of the facility. This would not have been possible if the process was theoretical or experimental.

Construction of the Centerpoint biorefinery facility will not start until well after Sierra has been operating. Fulcrum will not finance or construct Centerpoint if there are operational issues or concerns regarding Sierra. Lenders/investors would not take that risk, nor would Fulcrum.

The emissions information has been produced as part of a detailed modeling process that is based on USEPA guidance, equipment guarantees, and data gained from the extensive process trials. Further, most of the air emissions will be from natural gas combustion in equipment such as the auxiliary boiler (for steam production). This is very well understood equipment used in a variety of industrial processes with significant operating hours. This enables vendors to guarantee the emissions from such units. The same applies to emissions control equipment that will be used by Centerpoint. Fulcrum has a high degree of confidence in the projected emissions outlined in the air permit application.

Fulcrum Bioenergy issued a news release on May 24, 2022, that announced the completion of commissioning and the initial operations of its Sierra BioFuels Plant located outside of Reno, Nevada, and that the biorefinery began operations, processing prepared waste feedstock and successfully producing a high-quality hydrocarbon synthetic gas, or syngas. The news release can be found at the following website: https://fulcrum-bioenergy.com/wp-content/uploads/2022/05/2022-05-24-Sierra-Operations-Press-Release-FINAL.pdf

The U.S. EPA has published a report entitled, "Assessment of Municipal Solid Waste Energy Recovery Technologies - Final Report", U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-20/142, December 2020. This document can be accessed on the internet at: https://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=542242&Lab=CESER

The U.S. EPA 2020 report identified the following two (2) gasification facilities operating in North America that convert feedstock derived from municipal solid waste (MSW) into liquid fuel:

- Enerkem Alberta Biofuels, Edmonton, Alberta, Canada (producing ethanol). Additional information on this facility can be found at the following website: https://enerkem.com/company/facilities-projects/

- Sierra Energy, Fort Hunter Liggett, Monterey, California (producing diesel and electricity). Additional information on this facility can be found at the following website: https://sierraenergy.com/fort-hunter-liggett/

The U.S. EPA 2020 report also identified the following gasification facility that was still in development in 2020 that would convert feedstock derived from MSW into liquid fuel:

- Fulcrum BioEnergy, McCarran (outside of Reno), Nevada (will produce a synthetic crude oil to be processed into transportation fuel). Additional information on this facility can be found at the following website: https://fulcrum-bioenergy.com/facilities/

The information cited above from Fulcrum Centerpoint and the U.S. EPA 2020 report indicate that the proposed biorefinery process (two-step process using steam-reforming gasification and Fischer-Tropsch process) to convert Feedstock into renewable transportation fuel has been proven to work at two (2) gasification facilities operating in North America.

In its air permit application, Fulcrum Centerpoint provided information regarding the proposed biorefinery plant (description of process, emission factors and emission calculation methodology used to determine the potential to emit (PTE) of the proposed facility, state and federal rule

applicability, and all additional information provided as part of the permit application) and certified (signed by the responsible official) that the information was truthful, accurate, and complete. IDEM, OAQ reviewed all information provided by Fulcrum Centerpoint in its permit application, requested additional information and/or clarification when necessary, and determined that the information was sufficiently adequate for determining the potential to emit (PTE) of the proposed facility and the applicability of state and federal air rules and air regulations

While the Nevada facility is not yet fully operational, engineering data provided by Fulcrum indicates that Fulcrum will be able to comply with the requirements of the proposed permit. Therefore, IDEM OAQ has no justification for requiring a delay in the issuance of this proposed permit.

Accidents (Spills, Leaks, Fires, and Explosions)

IDEM, OAQ understands that local citizens have concerns about their personal safety related to potential accidents (spills, leaks, fires, and explosions) at the proposed plant and emergency preparedness and response capabilities. However, IDEM, OAQ does not have the authority to evaluate these types of issues as part of the air permit application and review process or to deny an air permit based on concerns about these types of issues. Please contact your local emergency management officials, the local fire department, and/or the Indiana State Fire Marshall for these concerns.

Fulcrum Centerpoint has indicated that each feedstock storage building will be equipped with a fire detection and suppression system. In addition, Fulcrum Centerpoint has indicated that it will implement an Emergency Response Plan that will identify the hazards and controls/responses for chemical spills, fires, earthquakes, and explosives.

Emergency Response Plan

Prior to construction and operation, Fulcrum Centerpoint will be required to apply for and obtain a solid waste processing permit from IDEM's Office of Land Quality (OLQ). The solid waste processing rules under 329 IAC 11-9-2 and 329 IAC 11-13.5-7 have provisions requiring a written emergency response plan. Pursuant to 329 IAC 11-2-10.1 ("Emergency response plan" defined), "Emergency response plan" means a document setting out an organized, planned, and coordinated course of action to be followed in case of an emergency such as fire, spills, contaminant release, or release of solid waste byproducts, such as gases or chemical contaminants, or leachate that could imminently threaten human health or the environment.

Fulcrum Centerpoint, LLC submitted an updated Emergency Response Plan on April 11, 2022, to IDEM, OLQ as part of its solid waste processing permit application (see VFC document #83302394, pages 134-172 of 184) that assigns responsibilities, establishes mandatory safety procedures, and provides for contingencies that may arise during the operation of the facility, including, but not limited to, fires, spills, and natural disasters.

IDEM, Office of Land Quality (OLQ) routinely inspects sources issued a solid waste processing permit under 326 IAC 11 to assure the requirements of the solid waste processing permit are being met.

Air Permit Requirements

The proposed air permit contains requirements related to preventive maintenance, deviations from permit requirements, annual compliance certifications, and emergencies.

Conditions B.13 and D.1.5 of the proposed air permit require that the Fulcrum Centerpoint prepare and maintain Preventive Maintenance Plans (PMPs) for each of the emission units and

control devices at the source. The PMPs shall specify the procedures and individual(s) responsible for inspecting, maintaining, and repairing emission units and control devices. Compliance with the PMP requirements will help Fulcrum Centerpoint to minimize the possibility of accidents at the plant. PMPs are typically kept on site so that on-site employees can effectively implement the PMPs and so that a copy is available for review by an IDEM, OAQ inspector. During an inspection, the IDEM, OAQ inspector will perform a records review, which includes review of PMPs, to determine if the source is in compliance with the PMP requirements.

If a leak, spill, fire, and/or explosion results in a deviation from any permit requirement or an exceedance of a permit limitation, then Fulcrum Centerpoint would be required to report the deviation(s) and any response steps taken as part of the Quarterly Deviation and Compliance Monitoring Report as specified in permit Section C.20 (General Reporting Requirements). Deviations must also be reported annually as part of the Annual Compliance Certification (ACC) Report. If there is an emergency (as defined under 326 IAC 2-7-1(12)) lasting one (1) hour or more that causes the source to exceed permit emission limitation, then Fulcrum Centerpoint would be required to notify IDEM, OAQ and submit an Emergency Occurrence Report Form as specified in permit Section B.14 (Emergency Provisions).

Permit Section B.14 (Emergency Provisions) contains the permit requirements related the occurrence of any emergencies at a source. An emergency is defined under 326 IAC 2-7-1(12) as follows:

> *"'Emergency' means any situation, including acts of God, arising from sudden and reasonably unforeseeable events beyond the reasonable control of the source that:*
>
> *(A) requires immediate corrective action to restore normal operation; and*
> *(B) causes the source to exceed an emission limit under a Part 70 permit due to unavoidable increases in emissions attributable to the emergency."*

Under permit Section B.14, for each emergency lasting one (1) hour or more, the Permittee is required to notify IDEM, OAQ within four (4) daytime business **hours** after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered. IDEM is aware that under certain circumstances it may not be possible to contact IDEM immediately when an emergency occurs, either due to the time of day the emergency occurs or due to the fact that the Permittee has dedicated its personnel to taking steps to correct the emergency, taking corrective actions to restore normal operation, and/or taking steps to mitigate the emissions. In addition, permit Section B.14 requires a source to submit an Emergency Occurrence Report Form for each emergency lasting one (1) hour or more within two (2) working days of the time when emission limitations were exceeded due to the emergency.
Failure to notify IDEM, OAQ as specified in permit Section B.14 shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

As specified in permit Section B.14, if Fulcrum Centerpoint claimed that an emergency occurred, Fulcrum Centerpoint would be required to keep properly signed, contemporaneous operating logs or other relevant evidence to demonstrate that an emergency occurred and shall make records available upon request. These records would need to include all relevant information regarding the emergency, including, but not limited to, the time and duration of the emergency and proof that the emergency met the definition of "emergency" under 326 IAC 2-7-1(12). IDEM, OAQ would evaluate any claim of an emergency to determine if it met the requirements of permit Section B.14 and 326 IAC 2-7-16.

Additional Information

For information about IDEM Emergency Response program for incidents involving spills to Indiana soil or waters, please see https://www.in.gov/idem/cleanups/investigation-and-cleanup-programs/emergency-response/.

If citizens witness or have evidence of any environmental emergency, accidental spill, leak, fire, or explosion at the proposed plant, IDEM, OAQ encourages citizens to contact local emergency management officials, report any spills to land or water by calling IDEM's 24-Hour Emergency Spill Line toll free at (888) 233-7745 or (317) 233-7745, and/or submit a complaint using one (1) or more of the three (3) different ways specified above under the subsection "Possible Future Violations".

If there are accidental spills, leaks, or instances of improper disposal and handling of pollutants that results in contaminated land or water at this proposed plant, the contamination must be assessed and either cleaned up or effectively managed to eliminate or prevent risk to human health or further degradation to the environment.

IDEM Office of Land Quality (OLQ) oversees investigation and cleanup actions at sites where contaminants have or may have been released. OLQ employs a variety of investigation and cleanup programs in partnership with other state agencies, municipalities, federal agencies, or responsible parties to investigate, assess, manage, and/or clean up contaminated properties. Additional information on IDEM OLQ's Investigation and Cleanup Programs can be found at the following website: https://www.in.gov/idem/cleanups/investigation-and-cleanup-programs/emergency-response/.

With respect to transportation of hazardous material by trucks/railcars in transit to Fulcrum Centerpoint, the Commercial Vehicle Enforcement Division of the Indiana State Police (ISP) enforces the hazardous material regulations contained in 49 CFR, Parts 107, 171-178, and 180. This agency routinely inspects hazardous shipments to assure that they are following U.S. DOT regulations. More information can be found at the following websites: https://www.in.gov/isp/commands/commercial-vehicle-enforcement/ and https://www.in.gov/isp/2557.htm. Information for Hazardous Waste Transporters can be found at the following website: https://www.in.gov/idem/waste/files/waste_transporters_hw_guidance.pdf

Regarding Comments about Fire at Brightmark in Ashley, Indiana

With respect to comments about the fire that occurred on May 14, 2021, at the Brightmark Plastics Renewal Indiana 2, LLC, plant in Ashley, Indiana, IDEM, OAQ has no information as to the cause of the fire, the types of material(s) involved in the fire, or the steps takes to put out the fire. In addition, IDEM, OAQ is not aware of any testing (air, water, or soil) that was done in the area following the fire.

If a permitted (Part 70 or FESOP) source such as Brightmark has a fire that results in a deviation(s) from any air permit requirement(s) or an exceedance of an air permit limitation(s), then that source would be required to report the deviation(s) and any response steps taken as part of a Quarterly Deviation and Compliance Monitoring Report. If a permitted source such as Brightmark has a fire that qualifies as an "emergency" as defined under 326 IAC 2-7-1(12) that lasts one (1) hour or more which results in a exceedance of a permit emission limit, then the source is required to notify IDEM, OAQ by telephone or facsimile within four (4) daytime business hours and submit an Emergency Occurrence Report Form within two (2) working days.

General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

Many commenters expressed concern over the local air quality (e.g., serious ozone nonattainment status of Lake County), its effect on human health, and the impact of additional air pollution from this source on human health and the environment.

IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

IDEM, OAQ relies on the scientific expertise of U.S. EPA which has developed the National Ambient Air Quality Standards (NAAQS) to protect public health and the environment.

National Ambient Air Quality Standards (NAAQS) and County Attainment Status

The federal Clean Air Act requires the U.S. EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants. These standards are set at levels that protect human health, including the health of sensitive persons, such as asthmatics, children, and the elderly. The NAAQS are often referred to as the federal health standards for outdoor air. More information about these pollutants is available at https://www.epa.gov/criteria-air-pollutants on U.S. EPA's website. The complete table of the NAAQS can be found at https://www.epa.gov/criteria-air-pollutants/naaqs-table.

The Clean Air Act requires that U.S. EPA conduct periodic review of the most current scientific information to determine if air quality standards are adequate to protect human health and general welfare. This review includes an integrated science assessment which is a comprehensive review of science judgments and risk and exposure assessments. An independent committee, the Clean Air Scientific Advisory Committee (CASAC), reviews all health information and makes recommendations to U.S. EPA on whether current health standards are protective of public health and welfare or should be revised. After any health standard recommendations have been approved and finalized through rulemaking, IDEM is required to follow the new standards. Additional information on the CASAC can be found at the following website: https://yosemite.epa.gov/sab/sabpeople.nsf/webcommittees/CASAC.

IDEM conducts sampling of the ambient air at monitoring stations around Indiana. This air monitoring is conducted to measure whether the NAAQS are being met. Information about Indiana's air monitoring system and monitoring results are available at https://www.in.gov/idem/airmonitoring/. Information about current and expected air pollution levels are on IDEM's SmogWatch site at https://apps.idem.in.gov/smogwatch/Today.aspx on the internet. For additional discussion regarding ambient air monitoring, see IDEM Response to General Statement 8 - Air Monitoring.

The federal CAA requires that, no later than one year after promulgation of a new or revised NAAQS for any of the six criteria pollutants, the governor of each state must submit a list of all areas within their state indicating how each would be classified under the new or revised standard. The classification choices are:

- Attainment: If air quality in an area meets the current NAAQS it is considered to be in "attainment", unless it contributes ambient air quality in a nearby area that does not meet the current NAAQS.
- Nonattainment: If air quality in an area exceeds the current NAAQS, or contributes to ambient air quality in a nearby area that does not meet the current NAAQS, it is considered to be in "nonattainment".
- Unclassifiable: If air quality data does not exist that enables an area to be deemed "attainment" or "nonattainment", it is considered to be "unclassifiable".

326 IAC 1-2-86 defines "unclassifiable (unclassified) areas" as "[a] geographical area which cannot be classified as attainment or nonattainment on the basis of available information, *but for the purpose of establishing emission limitations in the applicable rule, an area comparable to an attainment area*." (*emphasis added*)

Within one year of the governor's submittal, U.S. EPA announces a list of federally designated nonattainment areas. States may contest the designation of any areas within their borders that were not included in their own submissions. The public has the opportunity to comment on proposed plans before U.S. EPA makes a final decision.

Indiana attainment status designations are codified in the Code of Federal Regulations (CFR) at 40 CFR 81.315, which can be found at the following website: https://www.ecfr.gov/cgi-bin/text-idx?SID=eed1ca0ec6d31179af79405ddffaae05&mc=true&node=se40.18.81_1315&rgn=div8

Lake County Attainment Status

Detailed information on the attainment status for Lake County, Calumet Township, is provided below.

2008 and 2015 8-Hour Ozone Standards

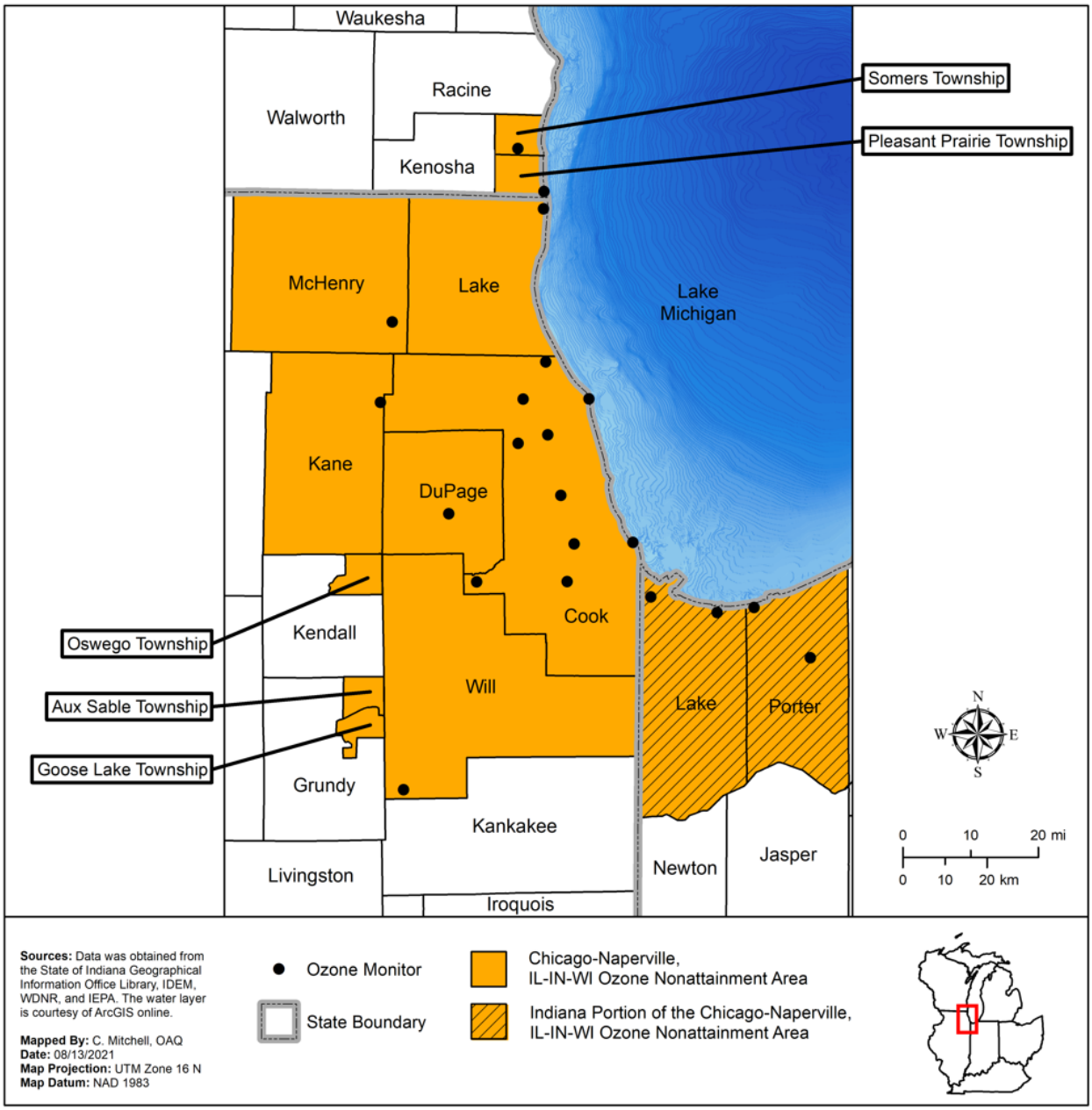
U.S. EPA, in the Federal Register Notice 87 FR 30821 dated May 20, 2022, designated Lake and Porter counties as attainment for the 2008 8-hour ozone standard effective May 20, 2022. A rulemaking for 326 IAC 1-4 is in process to adopt the U.S. EPA's attainment designation for the 2008 8-hour ozone standard for Lake and Porter counties.

All of Lake and Porter counties are currently classified as serious nonattainment under the 2008 8-hour ozone standard at 326 IAC 1-4. For this permit, the OAQ will rely on the 2008 8-hour ozone standard nonattainment designation under 326 IAC 1-4 until the rulemaking for 326 IAC 1-4 updating the 2008 ozone status for Lake and Porter counties is effective.

The northern portions of Lake and Porter counties are currently classified as marginal nonattainment under the 2015 8-hour ozone standard. The nonattainment area for the 2015 8-hour ozone standard, known as the Chicago, IL-IN-WI, nonattainment area, is comprised of Cook, DuPage, Grundy (partial county), Kane, Kendall (partial), Lake, McHenry, and Will counties, Illinois; Kenosha County (partial), Wisconsin; and Lake (partial) and Porter (partial) counties, Indiana. The Clean Air Act mandates that nonattainment boundaries include the entire Consolidated Metropolitan Statistical Area (CMSA), or Metropolitan Statistical Area (MSA) and all its Metropolitan Divisions. Therefore, the northern portions of Lake and Porter counties were included by U.S. EPA as a portion of the Chicago MSA and contains such cities as Gary, Hammond, East Chicago, Portage, and Valparaiso. In Illinois and Wisconsin, the nonattainment area contains the cities of Chicago, Elgin, Aurora, and Joliet in Illinois, and the city of Kenosha and Village of Pleasant Prairie in Wisconsin. The portion of northern Lake County designated as nonattainment for the 2015 8-hour ozone standard is Calumet Township, Hobart Township, North Township, Ross Township, and St. John Township.

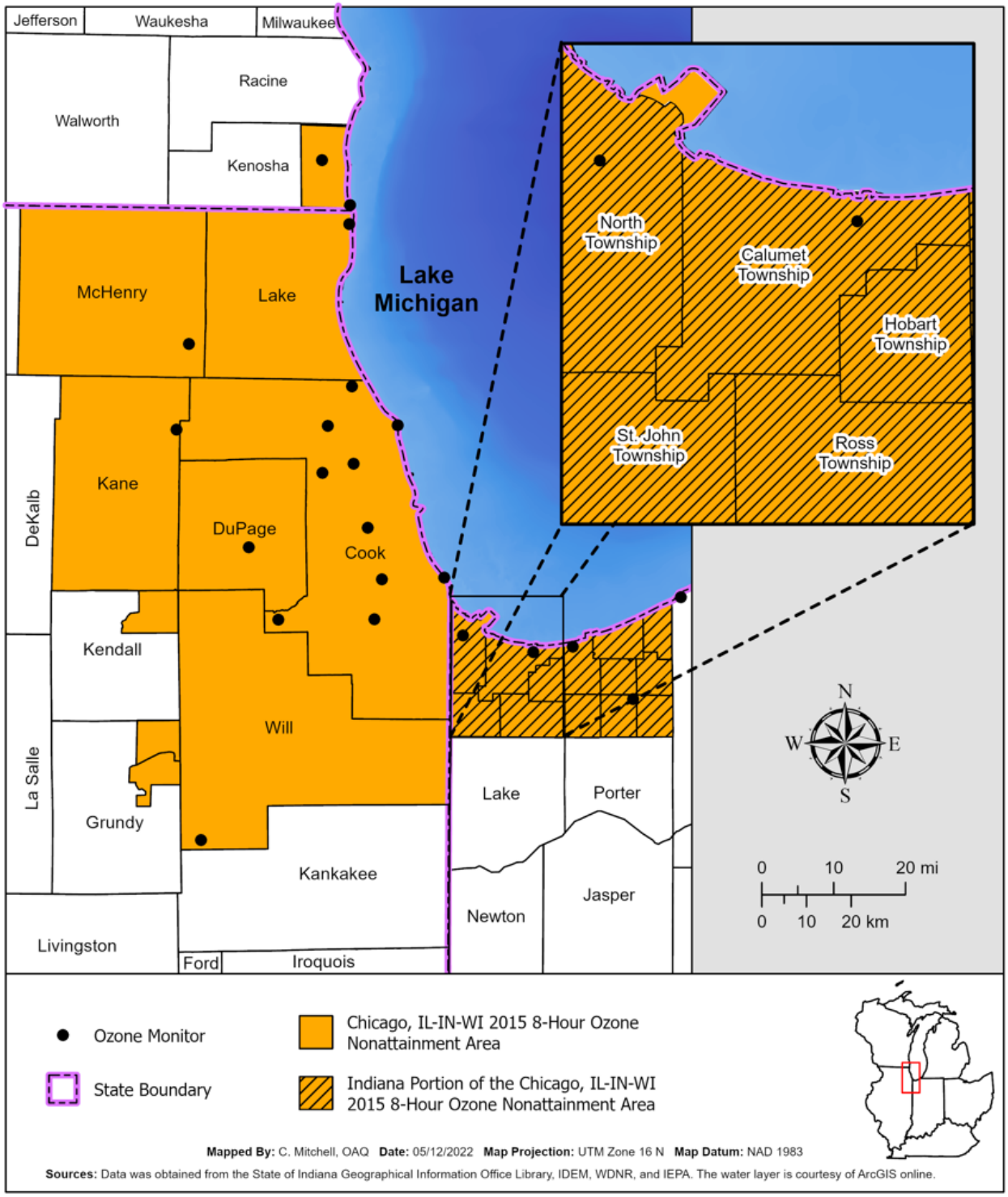
Maps of the Chicago-Naperville, IL-IN-WI, 2008 8-Hour Ozone Nonattainment Area and the Chicago, IL-IN-WI, 2015 8-Hour Ozone Nonattainment Area are provided below.

Map of the Chicago-Naperville, IL-IN-WI, 2008 8-Hour Ozone Nonattainment Area



It should be noted that the ozone monitors in Lake and Porter counties have not measured any three-year averages of the annual fourth highest daily maximum 8-hour average ozone concentrations or design values above the 2008 8-hour ozone standard of 0.075 parts per million (ppm) since the area was designated under the standard in 2012. Lake and Porter counties were originally classified as marginal nonattainment and subsequently bumped-up in nonattainment classification based on monitoring values measured at several SE Wisconsin and NE Illinois ozone monitors. The first bump-up from marginal to moderate occurred in 2016 and the second bump-up from moderate to serious nonattainment, which occurred in 2019 as design values at the Wisconsin and Illinois' monitors exceeded the 2008 8-hour ozone standard.

Map of the Chicago, IL-IN-WI, 2015 8-Hour Ozone Nonattainment Area



Lake County Attainment Status for Other Criteria Pollutants
U.S. EPA has classified Lake County as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, ambient air pollution levels for all other criteria pollutants are not considered harmful to human health, including the health of sensitive persons, such as asthmatics, children, and the elderly.

Ozone NAAQS and Air Quality Trends

Below is detailed information about the Ozone NAAQS:

- 2008 8-hour Ozone NAAQS
  For the 2008 8-hour ozone primary and secondary standards, the 4th highest daily maximum 8-hour ozone concentration measured at each monitor within an area is averaged on a three (3) year basis to determine the 8-hour design value. Air quality meets the 2008 8-hour ozone standards (attainment), when the three-year average of the 4th highest 8-hour ozone concentration is less than or equal to 0.075 ppm.

  Monitor design values are calculated at the end of each ozone season once all of the data from Indiana's monitoring network has been quality assured. Starting in the year 2016, Indiana's ozone season runs from March 1st through October 31st (note: Prior to 2016, Indiana's ozone season ran from April 1st through September 30th). Where two or more monitors are placed in an area, the monitor with the highest design value is used for the area's air quality designation.

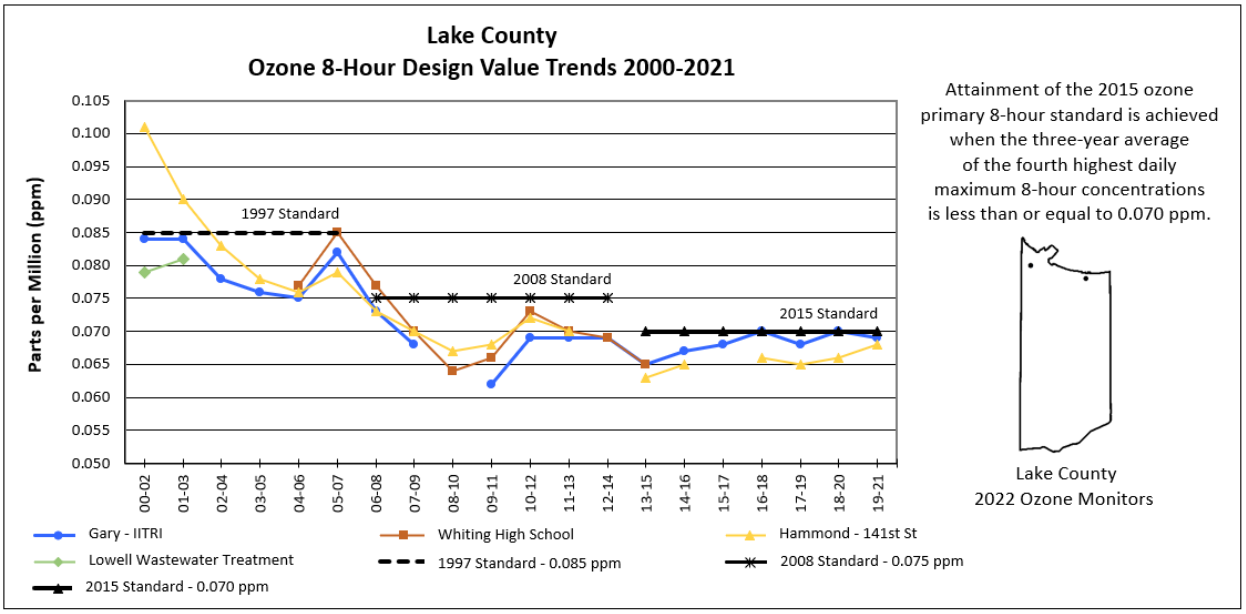
- 2015 8-hour Ozone NAAQS
  For the 2015 8-hour ozone primary and secondary standards, the 4th highest daily maximum 8-hour ozone concentration measured at each monitor within an area is averaged on a three (3) year basis to determine the 8-hour design value. Air quality meets the 2015 8-hour ozone standards (attainment), when the three-year average of the 4th highest 8-hour ozone concentration is less than or equal to 0.070 ppm.

  Monitor design values are calculated at the end of each ozone season once all of the data from Indiana's monitoring network has been quality assured. Starting in the year 2016, Indiana's ozone season runs from March 1st through October 31st. Where two or more monitors are placed in an area, the monitor with the highest design value is used for the area's air quality designation.

Lake County Ozone Trends from 2000 - 2021

Overall, the ambient levels of ozone in Lake County have decreased from the year 2000 to 2021 as shown by the 8-hour ozone design values in Chart 1 below. From 2009 to 2021, ambient air levels of ozone in the Lake County portion of the Chicago-Naperville, IL-IN-WI Metropolitan Statistical Area (MSA) were equal to or less than the 2008 8-hour ozone NAAQS of 0.075 ppm. From 2015 to 2021, ambient air levels of ozone in the Lake County portion of the Chicago-Naperville, IL-IN-WI Metropolitan Statistical Area (MSA) were equal to or less than the 2015 8-hour ozone NAAQS of 0.070 ppm.

Chart 1: Ozone 8-Hour Design Value Trends for 2000 – 2021



<u>NO_2 NAAQS and Air Quality Trends</u>

Below is detailed information about the NO_2 NAAQS:

- <u>1971 Annual NO_2 NAAQS</u>
  For the 1971 primary and secondary annual NO_2 standard, the measured hourly concentrations are averaged on an annual basis each calendar year to determine the annual design value. Air quality meets the 1971 annual NO_2 standards (attainment), when the annual arithmetic mean concentration in a calendar year is less than or equal to 53 parts per billion (ppb).

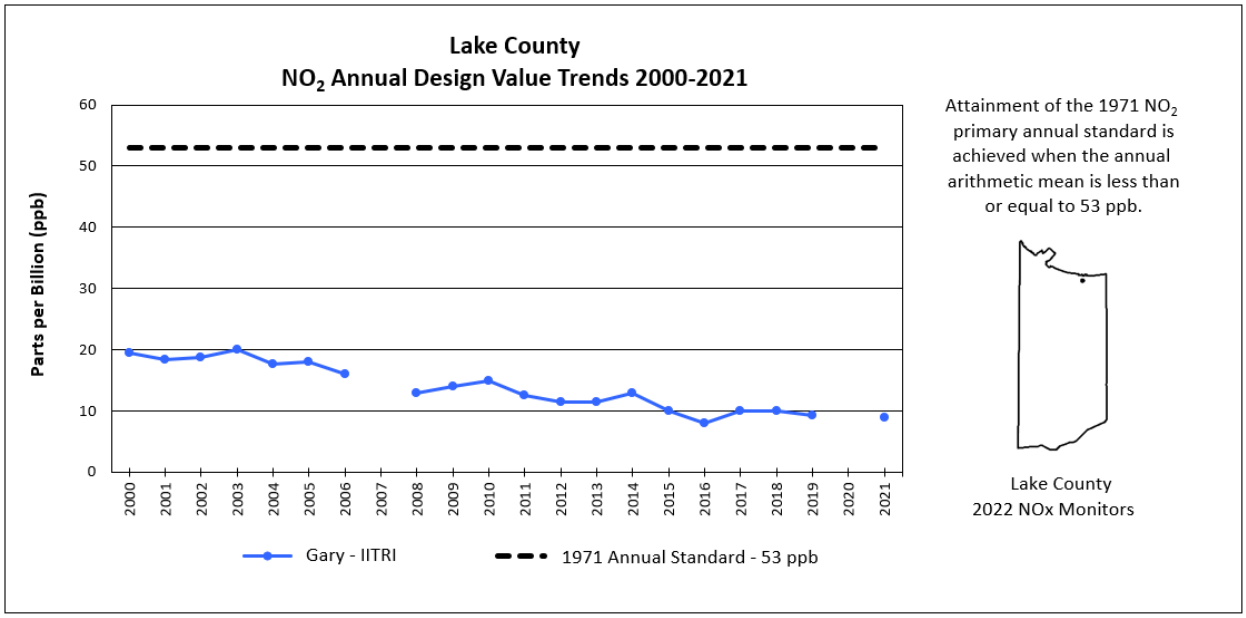
- <u>2010 1-hour NO_2 NAAQS</u>
  For the 2010 primary 1-hour NO_2 standard, the 98th percentile of the daily maximum 1-hour concentrations averaged on a three (3) year basis to determine the 1-hour design value. Air quality meets the 2010 1-hour NO_2 standard (attainment), when the three-year average of the 98th percentile of the daily maximum 1-hour concentrations is less than or equal to 100 ppb.

Lake County NO_2 Trends from 2000 - 2021

The ambient levels of NO_2 in Lake County from the year 2000 to 2021 are shown Charts 2 and 3 below.

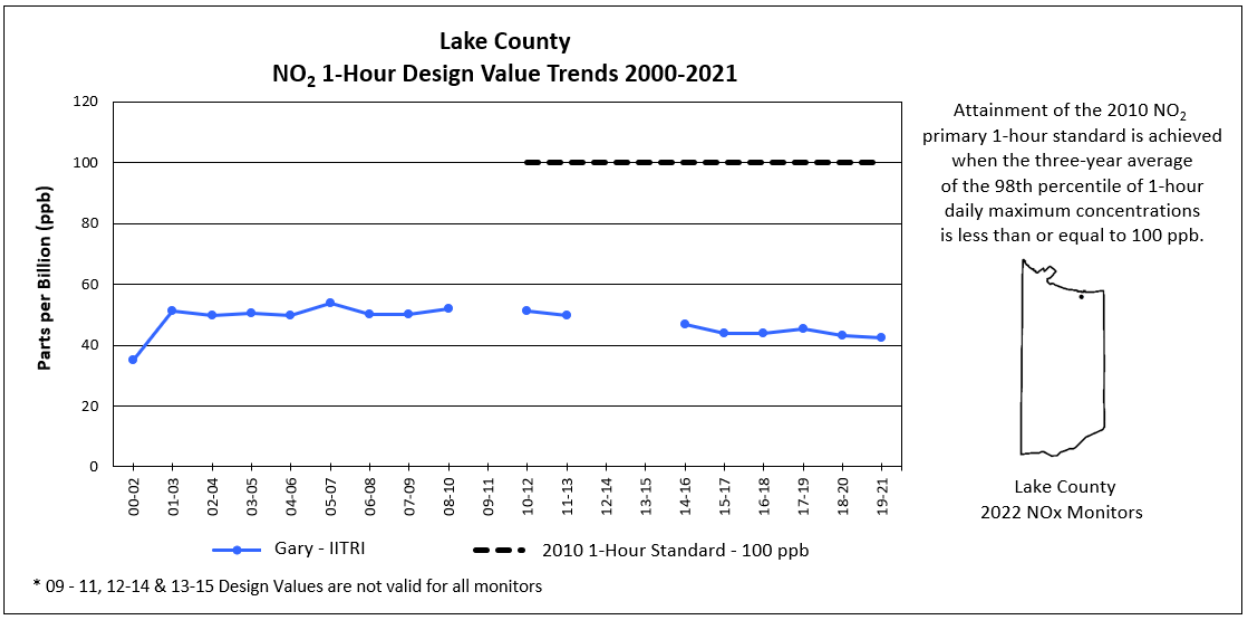
- <u>1971 Annual NO_2 NAAQS</u>
  A downward trend of the NO_2 annual design values over the 21-year time frame is illustrated in Chart 2. From 2000 to 2021, Lake County was in attainment (air quality met the NAAQS) for the 1971 annual NO_2 standards, since the NO_2 annual design values were less than 53 ppb.

Chart 2: NO_2 Annual Design Value Trends for 2000 – 2021



- <u>2010 1-hour NO_2 NAAQS</u>
  The NO_2 primary 1-hour design value trends over the 21-year time frame is illustrated in Chart 3. From 2000 to 2021, Lake County was in attainment (air quality met the NAAQS) for the 2010 1-hour NO_2 standard, since the NO_2 1-hour design values were less than 100 ppb.

Chart 3: NO_2 1-Hour Design Value Trends for 2000 – 2021



PM_{10} and $PM_{2.5}$ NAAQS and Air Quality Trends

Since several commenters expressed concern regarding the potential fugitive dust and particulate matter emissions and the local air quality, IDEM, OAQ has provided a summary of the PM10 and PM2.5 NAAQS attainment status and air quality trends in Lake County.

Detailed information on IDEM OAQ's ambient air monitoring program, see IDEM Response to General Statement 8 - Air Monitoring.

PM10 and PM2.5 NAAQS and Lake County Attainment Status

In order for an area to be designated in "attainment", air quality must meet the 2012 annual $PM_{2.5}$ standard, the 2006 24-hour (daily) $PM_{2.5}$ standard, and the 1987 24-hour (daily) PM_{10} standard. Three complete, consecutive years of monitoring data is used to make a determination about a given area. For example, an evaluation in 2021 will be based on data from 2018 to 2020.

Below is detailed information about the PM10 and PM2.5 NAAQS:

- 2012 Annual $PM_{2.5}$ NAAQS
  For the 2012 primary and secondary annual $PM_{2.5}$ standards, measured $PM_{2.5}$ concentrations are averaged on an annual rolling basis. Air quality meets the 2012 primary annual $PM_{2.5}$ standard (attainment) when the annual weighted arithmetic mean of the daily $PM_{2.5}$ concentrations over the three-year period are less than or equal to 12 micrograms per cubic meter (µg/m3). The 2012 secondary annual $PM_{2.5}$ standard is achieved when the annual weighted arithmetic mean averaged over the three-year period are less than or equal to 15 µg/m3. The data from each monitor is evaluated.

- 2006 24-hour $PM_{2.5}$ NAAQS
  For the 2006 primary and secondary 24-hour (daily) $PM_{2.5}$ standards, measured $PM_{2.5}$ concentrations are averaged on a 24-hour rolling basis. Air quality meets the 2006 primary and secondary daily standards (attainment), when the three-year average of the 98th percentile of measured concentrations does not exceed 35 µg/m3. The data from each monitor is evaluated.

- 1987 24-hour PM_{10} NAAQS
  For the 1987 primary and secondary 24-hour (daily) PM_{10} standards, measured PM_{10} concentrations are averaged on a 24-hour rolling basis. Air quality meets the 1987 primary and secondary daily standards (attainment), when the standard of 150 µg/m3 is not exceeded more than once per year on average over three years. The data from each monitor is evaluated.

- Design Value
  The three-year average is referred to as the design value. The annual design value is the three-year average of the weighted annual mean concentrations. The 24-hour design value is the three-year average of the 98th percentile of 24-hour concentrations.

  Monitor design values are calculated at the end of the year once all of the data has been quality assured. Where two or more monitors are located within the same area, the monitor with the highest design value is used for the air quality designation.

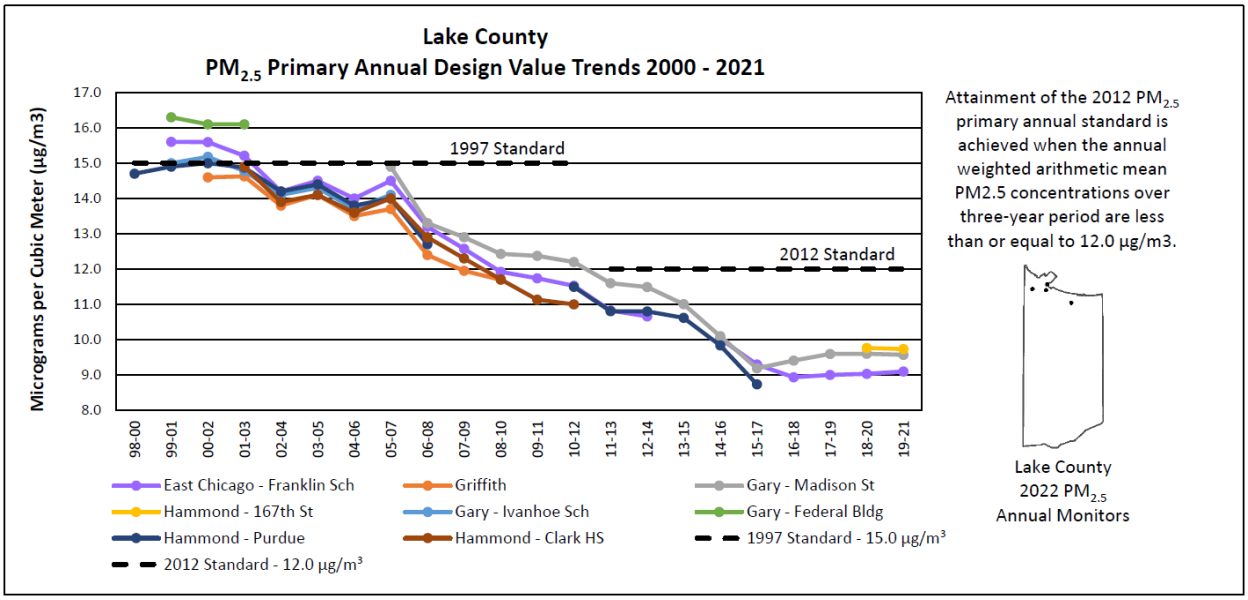
Lake County PM10 and PM2.5 Trends from 2000 - 2021

Overall, the ambient levels of $PM_{2.5}$ and PM_{10} in Lake County have decreased from the year 2000 to 2021 as shown Charts 4, 5, and 6 below.

- 2012 Annual $PM_{2.5}$ NAAQS
  A downward trend of the $PM_{2.5}$ primary annual design values over the 21-year time frame is illustrated in Chart 4. From 2013 to 2021, Lake County was in attainment (air quality met the NAAQS) for the 2012 annual $PM_{2.5}$ standard, since the $PM_{2.5}$ primary annual design values were less than 12 µg/m3.

  Note: U.S. EPA revised the annual $PM_{2.5}$ standard on December 14, 2012. Therefore, $PM_{2.5}$ primary annual design values are not comparable to the 2012 annual $PM_{2.5}$ standard until the year ending 2013. Prior to 2013 the standard was compared to the 1997 annual $PM_{2.5}$ standard of 15.0 µg/m3.

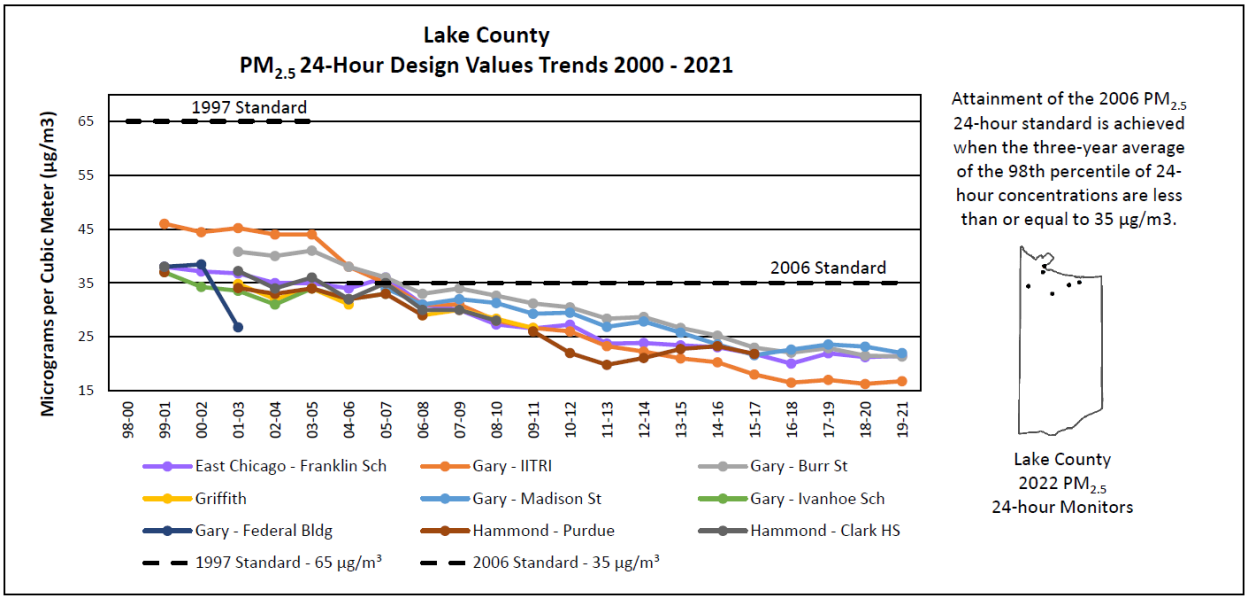
Chart 4: $PM_{2.5}$ Primary Annual Design Value Trends for 2000 – 2021



- 2006 24-hour $PM_{2.5}$ NAAQS
  A downward trend of the $PM_{2.5}$ 24-hour (daily) design values over the 21-year time frame is illustrated in Chart 5. From 2006 to 2021, Lake County was in attainment (air quality met the NAAQS) for the 2006 24-hour $PM_{2.5}$ standards, since the $PM_{2.5}$ 24-hour design values were less than 35 µg/m3.

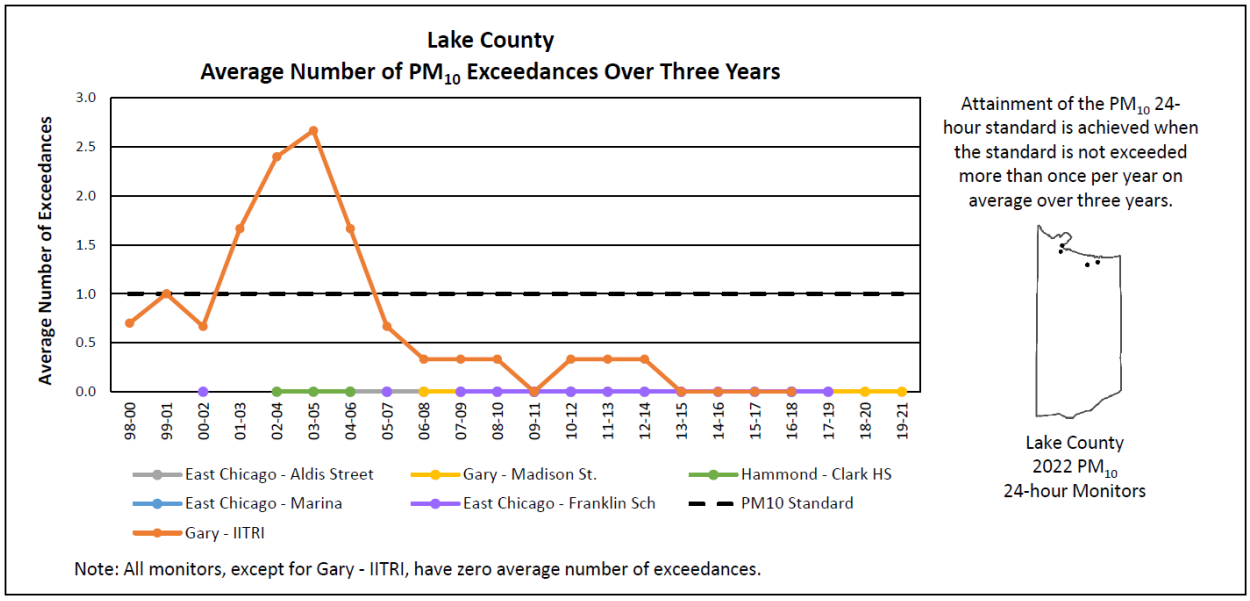
  Note: U.S. EPA revised the 24-hour $PM_{2.5}$ primary and secondary standards on December 18, 2006. Therefore, the $PM_{2.5}$ 24-hour (daily) design values are not comparable to the 2006 24-hour $PM_{2.5}$ standards until the year ending 2007. Prior to 2007 the standards were compared to the 1997 annual $PM_{2.5}$ standards of 65.0 µg/m3.

Chart 5: $PM_{2.5}$ 24-Hour Design Values Trends for 2000 – 2021



- <u>1987 24-hour PM_{10} NAAQS</u>
  The average number of exceedances of the 1987 24-hour (daily) PM_{10} standards over the 21-year time frame is illustrated in Chart 6. From 2007 to 2021, the cities of East Chicago, Hammond, Whiting, and Gary were in attainment (air quality meets the NAAQS) of the 1987 24-hour PM_{10} standards, since the PM_{10} standard of 150 µg/m3 was not exceeded more than once per year on average over three years.

Chart 6: Average Number of PM10 Exceedances Over Three Years for 2000 – 2021



Based on the data provided in the Charts 4, 5, and 6 above, overall, the ambient levels of $PM_{2.5}$ and PM_{10} in Lake County have decreased from 2000 to 2021.

U.S. EPA has classified Lake County or the city of Gary as attainment for the 2012 annual $PM_{2.5}$ standard, the 2006 24-hour (daily) $PM_{2.5}$ standard, and the 1987 24-hour (daily) PM_{10} standard. Therefore, ambient air pollution levels of $PM_{2.5}$ and PM_{10} are not considered harmful to human health, including the health of sensitive persons, such as asthmatics, children, and the elderly.

Impact of Air Pollution from this Source

IDEM, OAQ recognizes that air pollution emissions from this source and its effect on human health and the environment are of great concern to the commenters and local residents.

IDEM's mission is to implement federal and state regulations to protect human health and the environment while allowing for environmentally sound operations of industrial, agricultural, commercial, and government activities vital to a prosperous economy.

IDEM, OAQ issues air pollution permits to facilities that emit regulated levels of pollutants to the air. Permits require sources to comply with all health-based and technology-based standards established by the U.S. Environmental Protection Agency (EPA) and the Indiana Environmental Rules Board.

The proposed permit contains all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board, which will limit the amount of emissions from the facility to the very lowest level allowed by law. The permit also contains all applicable control device operating requirements, monitoring requirements, testing requirements, and associated record keeping and reporting requirements to assure that all permit limitations are enforceable as a practical matter and to assure that the source can demonstrate compliance with all applicable state and federal rules on a continuous basis.

This proposed permit is protective of human health and the environment and will allow for environmentally sound operations that may support a prosperous economy.

General Statement 8 - Air Monitoring

Some commenters expressed concerns about issues related to air monitoring.

IDEM Response to General Statement 8 - Air Monitoring

Summary of Air Monitoring in Indiana

The Indiana Department of Environmental Management (IDEM) regulates air quality to protect public health and the environment in the State of Indiana. Air monitoring data are required by regulation and are used to determine compliance with U.S. EPA's National Ambient Air Quality Standards (NAAQS). Other important uses of the air monitoring data include, the production of a daily Air Quality Index (AQI) report, daily air quality forecast report, support of short and long-term health risk assessments, identification of a localized health concern, and tracking long-term trends in air quality. Indiana monitors the six criteria pollutants which have NAAQS identified for them; carbon monoxide (CO), lead, nitrogen dioxide (NO2), ground-level ozone (O3), particulate matter (PM10 and PM2.5), and sulfur dioxide (SO2). Other pollutants which do not have ambient standards established for them are also monitored: toxics (volatile organic compounds, VOCs), metals, carbonyls, PM2.5 speciated compounds, ozone precursors, and carbon dioxide (CO2). In addition, meteorological data are also collected to support the monitoring and aid in analysis of the data.

IDEM presents two different types of air quality data, intermittent and continuous, on IDEM's Internet website https://www.in.gov/idem/airmonitoring/. Monthly and annual summary reports of pollutants collected by manual methods are available as well as hourly values from continuous

monitors. The Leading Environmental Analysis and Display System (LEADS) provides on-line access to Indiana's continuous air quality monitoring network. It has been available to the public since July 2007. LEADS offers access to near real-time data from 59 active and historic data from 12 discontinued continuous air monitoring sites across Indiana. This allows anyone to track pollutant and meteorological values throughout the day. In addition, past data back to 1998 are available as raw data and canned summary reports or user specified retrievals. Intermittent data from 41 sites are available on LEADS. Site information with site photographs can be found at the following website: http://idem.tx.sutron.com/cgi-bin/site_photo.pl

IDEM issues Air Quality Action Day (AQAD) advisories on days when ground level ozone pollution or fine particulate matter (PM2.5) could build to unhealthy levels in the outdoor air. IDEM issues AQAD advisories based on air quality forecasts, air quality standards, and Air Quality Index (AQI) categories. Typical conditions for ozone AQADs in Indiana are high temperatures approaching 80° Fahrenheit or above, clear skies, dry atmosphere, calm to light southerly winds, very little air mixing, high NOx values the previous night, and/or persistent high pressure over the eastern Midwest states and East Coast. Typical conditions for PM2.5 AQADs in Indiana are temperature inversions, light winds, clear skies, persistent high pressure, high humidity values, transport from high PM2.5 locations (such as wildfires), and/or warm and humid air over snow cover during the winter. When AQADs are predicted, Hoosiers can take action to protect their health and protect air quality. For additional information on AQAD advisories and actions to take during AQAD advisories, please see the following website: https://www.in.gov/idem/airquality/information-about/air-quality-action-day-aqad-advisories/

The Air Quality Index (AQI) is a health index which combines the evaluation of various air pollutants in order to provide an easily understood measure of air quality. The AQI focuses on health effects that can occur within a few hours or days after breathing polluted air. Air monitoring data are used to issue health alerts to warn the public of elevated pollution levels. The index provides a scale to which air quality is compared and indicates the associated health effects of concern. IDEM issues health alerts for high air pollutant levels based on the AQI. The AQI uses index numbers, health effect levels, and colors to communicate the health levels. The higher the AQI value, the greater the level of air pollution and the greater the chance of health impacts. For example, an AQI value of 50 represents good air quality and little potential to affect public health, while an AQI value over 300 represents hazardous air quality that could cause health effects. An AQI value of 100 generally corresponds to the National Ambient Air Quality Standard (NAAQS) for the pollutant, which is the level the United States Environmental Protection Agency (U.S. EPA) has set to protect public health. AQI values below 100 are generally regarded as satisfactory. When AQI values are above 100, air quality is considered to be unhealthy, first for certain sensitive groups of people, then for everyone as AQI values get higher. The Air Quality Index (AQI) report and additional information on the AQI can be found at the following website: http://idem.tx.sutron.com/cgi-bin/aqi_map.pl.

Extensive information about Indiana's air monitoring system and monitoring results is available at https://www.in.gov/idem/airmonitoring/ on IDEM's website.

SmogWatch is an informational tool created by IDEM to share air quality forecasts for each day. SmogWatch provides daily information about ground-level ozone and particulate matter air quality forecasts, health information, and monitoring data for seven regions of Indiana. Near real time data are available at http://idem.tx.sutron.com/cgi-bin/airfacts.pl.

Ambient Air Monitoring Network Plan

In October 2006, United States Environmental Protection Agency (U.S. EPA) issued final regulations concerning state and local agency ambient air monitoring networks. These regulations in 40 Code of Federal Regulations 58, Subpart B (40 CFR 58.10), require states to submit an annual monitoring network review to U.S. EPA. This network plan is required to

provide the framework for establishment and maintenance of an air quality surveillance system and to list any changes that are proposed to take place to the current network. Indiana's current Ambient Air Monitoring Network Plan is available at https://www.in.gov/idem/airmonitoring/indianas-ambient-air-monitoring-network/ on IDEM's website.

Locations of the monitors are reviewed annually pursuant to 40 CFR 58.10 and are subject to public comment. Comments on the ambient air monitoring network can be made during the public comment period for the 2023 network plan. IDEM, OAQ will evaluate the request and act if any changes are necessary to meet the monitoring goals and monitoring projects across the state. IDEM's contact for the monitoring plan is Steve Lengerich. Mr. Lengerich may be contacted by U.S. Mail at Steve Lengerich, IDEM/OAQ/AMB, 100 North Senate Avenue, Shadeland, Indianapolis, IN 46204-2251, by FAX at 317-308-3239 or by e-mail at slengeri@idem.IN.gov.

General Statement 9 - Pollution Control, Compliance Determination/Monitoring, and Stack Testing

Some commenters expressed concerns about issues related to permit requirements for pollution control, compliance determination, compliance monitoring, and stack testing.

IDEM Response to General Statement 9 - Pollution Control, Compliance Determination/Monitoring, and Stack Testing

The proposed permit requires the following pollution control, compliance determination, compliance monitoring, stack testing requirements, and associated record keeping and reporting requirements:

- Permit Section C.2 (Opacity) requires the source to comply with the opacity limits under 326 IAC 5-1-2.
- Permit Section C.5 (Fugitive Dust Emissions) prohibits the Permittee from allowing 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 Indiana Administrative Code (IAC) 6-4.
- Permit Section C.6 (Fugitive Dust Emissions) (added to the permit in IDEM Response to U.S. EPA Comment 2) requires the source to comply with the fugitive particulate matter, visible emission, and opacity limits and requirements under 326 IAC 6.8-10-3 and to control fugitive particulate matter emissions according to the Fugitive Dust Control Plan that is included as Attachment A to the operating permit.
- Permit Section C.7 (Lake County Particulate Matter Contingency Measures) (added to the permit in IDEM Response to U.S. EPA Comment 2) requires the source to comply with the with the applicable provisions of 326 IAC 6.8-11 (Lake County Particulate Matter Contingency Measures).
- Permit Condition D.1.6(a), (b), (c), and (d) require that the source perform initial and 5-year repeat stack testing for particulate matter (PM, PM10, and PM2.5) from the feedstock storage buildings, feedstock dryers, ash silos, and bed media silos, respectively.
- Permit Condition D.1.6(e) and (f) require that the source perform initial and 5-year repeat stack testing for NOx from the feedstock dryers and the pulse combustors controlled by a SCR system, respectively.
- Permit Condition D.1.6(g) and (h) require that the source perform initial and 5-year repeat stack testing for VOC from the pulse combustors controlled by a SCR system and the utility boiler controlled by an oxidation catalyst, respectively.
- Permit Condition D.1.6(i) requires that the source perform initial and 5-year repeat stack testing for CO from the utility boiler controlled by an oxidation catalyst.
- Permit Condition D.1.7 requires that the source determine the VOC concentration of wastewater samples taken from the wastewater treatment system once per week by using

one (1) of the test methods specified in 326 IAC 8-20-7(6) and to take wastewater flow rate measurements once per week.

- Permit Condition D.1.8 specifies the emission calculation methodologies that the source shall use to determine the VOC emissions from each of the storage tanks.
- Permit Condition D.1.9 specifies the equations that the source shall use to calculate the NOx, VOC, and CO emissions from the various emission units limited in Conditions D.1.2(h), D.1.2(i), and D.1.2(j), respectively.
- Permit Condition D.1.10 requires that baghouses or filters operate and control particulate matter (PM, PM10, and PM2.5) emissions for the feedstock storage buildings, feedstock dryers, ash silos, and bed media silos.
- Permit Condition D.1.11 requires that each of the selective catalytic reduction (SCR) systems operate and control NOx emissions from the pulse combustors and utility boiler at all times the respective pulse combustors and utility boiler are in operation.
- Permit Condition D.1.12 requires that the oxidation catalyst operate and control VOC emissions from the utility boiler at all times the utility boiler is in operation, that the utility boiler operate and control purge gas VOC emissions from the FT Reactor at all times the FT Reactor is in operation, except during periods of startup and shutdown, and that the flare (FLA) operate and control VOC emissions from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during periods of startup and shutdown .
- Permit Condition D.1.13 requires that the oxidation catalyst operate and control CO emissions from the utility boiler at all times the utility boiler is in operation.
- Permit Condition D.1.14 contains the NOx and O2 (or CO2) continuous emission monitoring systems (CEMS) requirements for the utility boiler SCR system.
- Permit Condition D.1.15 requires that the source sample and analyze the purge gas stream from the FT Reactor for HAP content once per week and to comply with instrument calibration requirements.
- Permit Conditions D.1.16 contains the requirements for when a NOx continuous emissions monitoring system (CEMS) is down due to breakdown, malfunction, or maintenance.
- Permit Conditions D.1.17 contains the pressure drop, temperature, and ammonia injection rate requirements for the selective catalytic reduction (SCR) systems.
- Permit Conditions D.1.18 and D.1.19 contain the temperature and duct pressure or fan amperage monitoring requirements for the selective oxidation catalyst.
- Permit Condition D.1.20 requires that the source monitor the presence of a flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame when the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor are in operation.
- Permit Condition D.1.21 requires that the source install and operate a continuous bag leak detection system (BLDS) for each of the baghouses controlling the feedstock storage buildings (FDSTG-1, FDSTG-2, and FDSTG-3) and feedstock dryers (DRYER-1, DRYER-2, and DRYER-3), and each of the filters controlling the ash silos (ASH1, ASH2, and ASH3) and bed media silos (BMS1, BMS2, and BMS3) and comply with the BLDS requirements specified in Condition D.1.21(b).
- Permit Condition D.1.22 requires that the source comply with baghouse broken or failed bag detection requirements.
- Permit Condition D.1.23 requires that the source sample and analyze the exhaust gas stream from the Sulfur Removal Unit (SRU) once per day in order to determine the H_2S content and to comply with instrument calibration requirements.
- Permit Conditions D.1.24 through D.1.27 contain all associated record keeping and reporting requirements.
- Attachment A of the permit includes a Fugitive Dust Control Plan (FDCP). As part of the FDCP, dust control measures shall be performed as necessary, including requiring that delivery and shipping trucks adhere to a posted facility speed limit of 20 miles per hour, vacuum sweeping, flushing, and/or wet power brooming of paved roads and parking lots, maintenance of the roadway surface and application of chemical dust suppressant(s) as necessary, limiting the height from which the slag is dropped into the roll-off or hopper bins

and the height from which the slag is loaded into trucks as necessary, requiring that Feedstock will be unloaded in one (1) of the three (3) separate Feedstock storage buildings, which are each enclosed with solid walls and doors that will be closed when the facility is not in operation or when feedstock deliveries are not being made, minimizing the footprint of any areas of land disturbance(s) and the reestablishment of natural foliage cover, controlling fugitive dust from any disturbed land(s) using water, chemical dust suppressants, berms, wind fences and/or boundary fencing, and controlling fugitive dust from any unnecessarily disturbed land(s) using landscaping and/or re-seeding. Additionally, the FDCP contains requirements for visual monitoring, recordkeeping, an employee/contractor training program. Please see the Attachment A of the permit for the entire Fugitive Dust Control Plan (FDCP).

IDEM, OAQ has determined that the initial and 5-year repeat stack testing requirements included in the permit are sufficient to demonstrate compliance with the PM/PM10/PM2.5, NOx, VOC, and CO limitations.

If IDEM, OAQ determines that additional stack testing was necessary to assure compliance with an applicable requirement, then IDEM, OAQ could require the additional stack testing at any time by issuing an order under 326 IAC 2-1.1-11. The required timeframe for conducting the additional stack testing would be determined by IDEM, OAQ at that time. As stated by Section C.11 (Compliance Requirements), the commissioner (i.e., IDEM) 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.

The IDEM, OAQ Compliance and Enforcement Branch may choose to observe any stack test and will review all stack test protocols and results. Regular inspections, regular stack testing, along with compliance monitoring, record keeping and reporting, will allow IDEM, OAQ to determine if Fulcrum Centerpoint is in continuous compliance with all air permit terms and conditions.

The public can view any documents related to this source, including IDEM inspection reports, any violations, stack test reports, any Quarterly Deviation and Compliance Monitoring Reports, Annual Compliance Certification (ACC) Reports, and any other reports submitted by Fulcrum Centerpoint on IDEM's Virtual File Cabinet (VFC) (https://vfc.idem.in.gov/DocumentSearch.aspx).

For additional information and guidance on stack testing, please see the following website and guidance documents:

- IDEM, OAQ Stack Tests: https://www.in.gov/idem/aircompliance/stack-tests/
- IDEM, OAQ Stack Test Guide: https://www.in.gov/idem/aircompliance/files/stack_test_guide.pdf
- Clean Air Act National Stack Test Guidance (April 27, 2009): https://www.epa.gov/sites/production/files/2013-09/documents/stacktesting_1.pdf

General Statement 10 - Feedstock Materials

Many commenters had questions and/or concerns about the Processed Engineered Feedstock ("Feedstock") materials that would be used at the Fulcrum Centerpoint biorefinery.

IDEM Response to General Statement 10 - Feedstock Materials

In the air permit application, Fulcrum Centerpoint specified it will use a Processed Engineered Feedstock ("Feedstock") derived from municipal solid waste (MSW) for its proposed biorefinery. Feedstock for the proposed biorefinery will be produced at separately permitted Feedstock Processing Facilities (FPFs), which will use commercially proven processing equipment to shred and sort municipal solid waste (MSW) with sequential steps recovering valuable recyclable materials, removing unwanted components of the waste stream, and improving the physical and compositional attributes of the Feedstock for renewable fuel production in the biorefinery. The Feedstock composition will remain unchanged and will be delivered to the proposed site, whereupon it may be temporarily stored, before being fed into the process.

Fulcrum Centerpoint, LLC, provided on its website (https://centerpoint.fulcrum-bioenergy.com/) a Question and Answer (Q&A) document to respond to questions received from the Gary Advocates for Responsible Development (GARD). The document included the following information in the box below regarding the Feedstock:

Excerpts from Q&A Document: Fulcrum Response to GARD (dated 12-21-2021)

At our two feedstock processing facilities outside of Gary, we sort, separate and process MSW to remove recyclable products and other unsuitable materials. Our feedstock is non-hazardous and consists of paper, cardboard, timber, textiles, soft plastic and organic material. The sorting process is designed to sort and separate municipal solid waste into a highly consistent feedstock for gasification. Fulcrum has operated and tested the Sierra Biofuels ("Sierra") Feedstock Processing Facility ("FPF") in Nevada since 2016 to ensure that the process could reliably produce feedstock that meets Fulcrum's tight specification for gasification.

The gasification process used for Sierra and Centerpoint is licensed from an experienced supplier who has tested the Fulcrum-specific feedstock and provided a performance guarantee for their design.

Fulcrum has also taken several MSW samples from the region and processed it into feedstock at the Sierra FPF in Nevada. This was done to confirm that the feedstock is of a similar composition and meets Fulcrum's specification. The results are summarized in the table below.

Feedstock Composition	Feedstock Characterization Average (weight %)
Mixed Paper	46
Film and Other Plastic	30
Wood	8
Textiles	8
Food/Yard Waste	2
Ferrous	0.1
Non-Ferrous	0.8
Inerts	2
Fines (<2")	4

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On December 21, 2021, Fulcrum Centerpoint, LLC, submitted a solid waste processing permit application (see VFC document # 83257441, pages 6-8 of 192) to IDEM Office of Land Quality (OLQ) that included the following information in the box below regarding the Feedstock:

Solid Waste Processing Permit Application (Received December 21, 2021), Pages 6-8 of 192:

1 ENGINEERING REPORT

***

1.3 Waste Information

1.3.1 Types of Feedstock to be Processed

The Facility will only accept the Feedstock from the dedicated Fulcrum FPFs and convert it into renewable transportation fuel using a non-combustion, steam-reforming gasification conversion technology and state-of-the-art FT process. This authorized Feedstock is the only material that will be accepted at the Facility and is comprised of the organic and carbon-based fraction of MSW, and commercial and industrial waste streams that were previously destined for landfill disposal. Moreover, all Feedstock received at the Facility has been produced from MSW previously inspected and approved for landfill disposal at commercial transfer stations before being processed at Fulcrum's FPFs into Feedstock.

The expected Feedstock composition is as follows:

Table 1 - Feedstock Properties

Feedstock Composition	Feedstock Characterization Average (wt%)
Mixed Paper	46
Film and Other Plastic	30
Wood	8
Textiles	8
Food/Yard Waste	2
Ferrous	0.1
Non-Ferrous	0.8
Inerts	2
Fines (<2")	4

1.3.1.1 Proposed Sampling

Fulcrum has conducted several waste characterizations in the Greater Chicago area. The most recent was completed in April 2021, which confirmed very similar composition and physical attributes to MSW from Reno, NV, the location of Fulcrum's first facility, Fulcrum Sierra Biofuels ("Sierra"). The samples collected in April 2021, where then processed at the Sierra FPF into Feedstock, which was further characterized and tested to confirm it met Fulcrum's Feedstock specification. Fulcrum will continue to sample and characterize MSW as the project is developed.

1.3.1.2 Feedstock Control Procedures and Management of Incompatible Feedstock

The Facility only accepts Feedstock materials from the FPFs and does not accept the following "Prohibited Materials":

- Regulated Hazardous Waste (as defined by 329 IAC 11-2-15)
- Polychlorinated Biphenyl ("PCB") Waste
- Bulk or Non-containerized Liquid Waste
- Sludge and Other Wastewater Treatment Solids
- Asbestos and asbestos-containing materials

- Source Separated Special Waste (Used tires, medical waste, used oil and filters, batteries)

The FPFs (not included in this application) will use industry best practices and procedures to detect, prevent and control the receipt of prohibited materials.

1.3.3 Feedstock Sources
Feedstock will be supplied to the Facility from two (2) FPFs. One FPF will be located offsite in Illinois and the other will be located in Northwest Indiana. Each FPF will be individually permitted.
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On December 21, 2021, Fulcrum Centerpoint, LLC, submitted a solid waste processing permit application (see VFC document # 83257441, pages 70-71 of 192) to IDEM Office of Land Quality (OLQ) that included the following information in the box below regarding the Feedstock:

Solid Waste Processing Permit Application (Received December 21, 2021), Pages 70-71 of 192:

Site Operating Plan (SOP)
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2.0 FEEDSTOCK ACCEPTANCE AND MANAGEMENT

2.1 <u>Feedstock Acceptance</u>

2.1.1 <u>Authorized Feedstock</u>

The Facility's Prepared Feedstock is comprised of the carbon rich fraction of Municipal Solid Waste ("MSW"), including organics, timber, textiles, paper, cardboard and plastics, destined for landfill disposal. Approximately 2,300 tons per day of Feedstock will be delivered to the Facility by trucks from Monday to Friday. Feedstock may also be delivered on Saturday, Sunday or holidays. All Feedstock received at the Facility will be prepared at a separate Feedstock Processing Facilities ("FPF"). As described in Section 1.1, Feedstock is delivered to the Facility's enclosed Feedstock storage buildings in Plant Area A. The process block flow diagram for Plant Area A is provided in Exhibit A.

2.1.2 <u>Prohibited Materials</u>
Feedstock delivered to the Site from the FPF shall not contain, nor shall the Facility accept the following materials ("Prohibited Materials"):

- Regulated Hazardous Waste;
- Polychlorinated Biphenyl (PCB) Waste;
- Bulk or Non-containerized Liquid Waste[1];
- Sludges and Other Wastewater Treatment Solids;
- Asbestos and asbestos containing materials; and
- Source Separated Special Waste (Used tires, medical waste, used oil and filters, batteries).

[1]Any Feedstock that is determined to contain "free liquids" as deemed by EPA Method 9095 (Paint Filter Test), as described in "Test Methods for Evaluating Solid Wastes, Physical Chemical Methods" (EPA Publication Number SW-846)

2.1.3 Measures for Controlling Prohibited Materials

a. Procedures for Detection

Prepared Feedstock will be delivered to the Facility by trucks after being processed, sorted, shredded and dried at FPFs, located in Greater Chicago and Northwest Indiana. At the FPF, MSW will be inspected for the presence of Prohibited Materials and other materials that may contaminate the Feedstock and impact health or safety at the Facility. The FPF personnel will be responsible for inspecting incoming loads of MSW. Any identification of regulated hazardous waste will be separated and properly handled for removal.

b. Prohibited Materials Training

Facility personnel will be trained to inspect Feedstock. Equipment operators will be trained in inspection procedures for prohibited materials. The personnel will be trained on an on-the-job basis by their supervisors. Records of employee training on prohibited materials control procedures will be maintained in the Facility operating record. Facility personnel will be trained to look for the following:

- Hazardous Waste
- DOT hazard placards or markings
- Liquid wastes and sludges
- Asbestos and asbestos containing materials
- Powders or dusts
- Odors or chemical fumes
- Bright or unusual colored wastes

If any hazardous waste is identified in an incoming load of Feedstock, then that load will be isolated to an area out of the flow of traffic, and personnel will further assess the load. If the load is determined to contain prohibited materials a certified hazardous waste contractor will be engaged to remove the material in conformance with all applicable laws.

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Fulcrum has submitted documentation that the requirements of 40 CFR Part 241, Subpart B [Identification of Non-Hazardous Secondary Materials That Are Solid Waste When Used as Fuels or Ingredients in Combustion Units] were followed when self-determining that the Feedstock would be a non-waste if it were used as fuel or ingredient in a combustion unit at the proposed biorefinery. Pursuant to 40 CFR Part 241.3(b)(4), the legitimacy criteria in 40 CFR Part 241.3(d)(1) or (d)(2) apply after the non-hazardous secondary material (NHSM) is processed to produce a fuel or ingredient product. Fulcrum will keep all necessary records that demonstrate that the Feedstock material meets the legitimacy criteria specified in 40 CFR Part 241.3(d)(1) or (d)(2) and records that document how the MSW NHSM is processed into Feedstock at the FPFs.

A copy of the NHSM non-waste self-determination provided by Fulcrum is included as additional information for the permit application and is available for public review via IDEM's Virtual File Cabinet (VFC) at: https://vfc.idem.in.gov/DocumentSearch.aspx.

General Statement 11 - Incineration

Several commenters stated, implied, or had concerns that proposed biorefinery gasification process would be incinerating, combusting, or burning feedstock materials.

IDEM Response to General Statement 11 - Incineration

Proposed Biorefinery Gasification Process

For its proposed biorefinery, Fulcrum Centerpoint will use a Processed Engineered Feedstock ("Feedstock") material derived from municipal solid waste (MSW).

The proposed biorefinery will "break down" and convert the Feedstock materials into diesel or jet fuel using a two-step thermochemical process of steam-reforming gasification in an oxygen-deficient atmosphere (producing syngas) and Fischer-Tropsch (FT) synthesis (producing "syncrude" FT liquids that are further upgraded and refined to diesel or jet fuel). The gasification process will not burn, combust, or incinerate the Feedstock materials (i.e., no direct flame will be applied to the Feedstock materials in the gasifier, nor will a flame be propagated as a result of the heating). The proposed gasification and the downstream processes will be fully contained. Prior to conversion to diesel or jet fuel, the syngas will go through a multistep clean-up process to remove contaminants such as sulfur, chlorine, and metals, which will be contained, captured, handled, and treated for disposal.

U.S. EPA Information

The following sources of U.S. EPA information were reviewed to understand how the proposed biorefinery would be categorized under federal air pollution regulations.

1. U.S. EPA Determination from Douglas K. McDaniel (U.S. EPA) to Patrick D. Traylor (Hogan and Hartson, LLP, on behalf of Fulcrum BioEnergy, Inc.) listed on the Applicability Determination Index (ADI) (https://cfpub.epa.gov/adi/) under the title, "Conversion of Post-Sorted Municipal Solid Waste Feedstock", ADI Control Number 1000019 (dated March 30, 2010). This determination can be accessed at: https://cfpub.epa.gov/adi/index.cfm?fuseaction=home.dsp_show_file_contents&CFID=22402543&CFTOKEN=a36b6c76f88c8d1b-47DDEFB5-09D0-9A1F-7E0E38F846D9F2CA&id=1000019

   In this determination, the U.S. EPA determined that 40 CFR Part 60, Subpart AAAA – New Source Performance Standards for New Small Municipal Waste Combustion Units would not apply to the Fulcrum BioEnergy (McCarran, Nevada) syngas generation units or the air pollution control flare, since Fulcrum's syngas gasification process is neither combustion nor pyrolysis and the flare would be considered air pollution control equipment and therefore would be excluded from the definition of "municipal waste combustion unit" as defined in Subpart AAAA. This determination was based on the proposed Fulcrum BioEnergy facility in McCarran, Nevada, which intended to convert post-sorted municipal solid waste feedstock into a synthetic gas that would be processed to produce ethanol and renewable power.

2. The U.S. EPA published a report entitled, "Assessment of Municipal Solid Waste Energy Recovery Technologies - Final Report", U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-20/142, December 2020. This document can be accessed on the internet at: https://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=542242&Lab=CESER

In the U.S. EPA report, it is explained that waste "conversion technologies" such as gasification and pyrolysis differ from the conventional waste-to-energy (WTE) process in that they do not directly combust municipal solid waste (MSW), but instead convert MSW feedstock via partial-oxygen or oxygen-absent thermochemical processes into gases that can be combusted to produce electricity or further processed into a liquid fuel or chemical commodity product. Excerpts from this report are included in the box below:

Excerpts from U.S. EPA Report: Assessment of Municipal Solid Waste Energy Recovery Technologies - Final Report

Executive Summary (Page xi)

A conventional waste-to-energy (WTE) facility accepts unprocessed municipal solid waste (MSW) which is burned in a large combustion unit to generate electricity or utilized in a combined heat and power system.***

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Waste "conversion technologies" such as gasification and pyrolysis are less established in the US and the world. These technologies differ from conventional WTE in that they do not directly combust MSW. Instead they convert MSW feedstock via partial-oxygen or oxygen-absent thermochemical. The resulting gases can be combusted to produce electricity or further processed into a liquid fuel or chemical commodity product. Such conversion technologies are considered "energy recovery" and preferable to "treatment and disposal" on EPA's waste management hierarchy.***

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Chapter 1: Introduction (Page 2)

Currently, there are 73 WTE facilities operating in the US, with the majority utilizing mass burn combustion (Appendix A). Most of these facilities have been operating for more than 20 years. The West Palm Beach WTE facility started operation on July 18, 2015 and was the first one built since 1995.[14] More recently, the focus has been on emerging waste-to-energy technologies that convert waste into energy products rather than burn it in a combustion unit. These "conversion technologies" differ from mass burn WTE facilities in that they do not directly combust feedstock but rather convert it via partial-oxygen or oxygen-absent thermochemical processes. The resulting gases can be combusted to produce electricity or further processed into a liquid fuel or chemical commodity product. ***

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Chapter 3: MSW Gasification (Page 13)

Gasification is a thermal process that, in a controlled oxygen environment, converts organic or fossil fuel carbon-containing material – such as coal, petroleum, plastics, or biomass – to syngas, char, and ash. The process is similar to pyrolysis, except that oxygen (as air, concentrated oxygen, or steam) is added to maintain a reducing atmosphere in the reactor. A reducing atmosphere exists when the quantity of oxygen available is less than the stoichiometric ratio for complete combustion. The process primarily forms carbon monoxide and hydrogen, and other constituents such as methane, particularly when operating at lower temperatures. The primary product of gasification, syngas, can be converted into heat, power, fuels, fertilizers and chemical products, or used in fuel cells.

3.1 MSW Gasification Process Description (Page 13)

The literature and technology vendors use different names for gasification and different variations for gasification processes in their technology descriptions which can cause confusion. Technological processes can be simplified into three core types of gasification, including:

- **High temperature gasification**—High temperature gasification reactors can reach up to 1,200°C and produce an inert byproduct, or slag, that does not need further processing to be stabilized. The syngas produced may be combusted to generate steam, which can be used for power and/or heat generation; however, the resultant syngas may also be used for other applications such as chemicals production. This technology may process a mix of carbonaceous waste including paper, plastics, and other organics with a moisture content of up to 30%. Higher moisture content feedstock would likely require drying before entering the reactor chamber.

- **Low temperature gasification**—Low temperature gasification reactors operate at temperatures between 600 and 875°C and produces syngas as the main product and ash as a byproduct, which may require stabilization. The ash can be sent to a vitrification[34] process to makes it inert and available for other uses. Syngas is typically used for electricity generation using an Internal Combustion Engine. This process can also recover steam energy.

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3. Regulation of Oil-Bearing Hazardous Secondary Materials From the Petroleum Refining Industry Processed in a Gasification System To Produce Synthesis Gas, Federal Register 73 FR 57 (dated January 2, 2008), Action: Final rule. This document can be accessed on the internet at:
https://www.govinfo.gov/content/pkg/FR-2008-01-02/pdf/E7-25240.pdf

In this final rulemaking, the U.S. EPA agreed with a U.S. Department of Energy (DOE) report that concluded "that gasification and incineration are distinct processes that can be distinguished by a number of factors". An excerpt from this federal register is provided in the box below:

Excerpt from Federal Register 73 FR 57

While some commenters have argued that gasification of oil-bearing hazardous secondary materials is more a waste management process involving incineration than a petroleum refining process, we refer to the conclusions drawn in a DOE report contrasting incineration and gasification. DOE concluded, and we agree, that gasification and incineration are distinct processes that can be distinguished by a number of factors. As discussed in the report, the factors distinguishing the two processes are: (1) Incinerators are designed to maximize the conversion of feedstock to carbon dioxide and water; gasifiers are designed to maximize the conversion of feedstock to carbon monoxide and hydrogen; (2) incinerators utilize large quantities of excess air; gasifiers utilize small quantities of oxygen; (3) incinerators operate in a highly oxidizing environment; gasifiers operate in a reducing environment; (4) incinerators discharge their flue gas to the environment as a waste; gasifiers utilize their synthesis gas for ongoing chemical, fuel production or power production as a product gas.[17]

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Footnote:
[17]A Comparison of Gasification and Incineration of Hazardous Waste—Final Report. United States Department of Energy, National Energy Technology Laboratory (NETL). 3610 Collins Ferry Road. Morgantown, West Virginia 26505. DCN 99.803931.02. March 30, 2000.
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4. Potential Future Regulation Addressing Pyrolysis and Gasification Units, Federal Register 86 FR 50296 (dated September 8, 2021), Action: Advance notice of proposed rulemaking. This document can be accessed on the internet at: https://www.govinfo.gov/content/pkg/FR-2021-09-08/pdf/2021-19390.pdf

In this advance notice of proposed rulemaking (ANPRM), the U.S. EPA explained that gasification is conducted in a "reducing (i.e., oxidation or combustion-preventing) atmosphere, where the quantity of oxygen available is less than the stoichiometric ratio (i.e., amount needed for complete combustion of the feed material)". Excerpts from this federal register are provided in the box below:

Excerpts from Federal Register 86 FR 50296

I. General Information

A. What is the purpose of this ANPRM?

The Agency is seeking comments and data to assist in the consideration of potential changes to existing regulations under Clean Air Act (CAA) section 129 or the development of regulations pertaining to pyrolysis and gasification units that are used to convert solid and semi-solid feedstocks, including solid waste (e.g., municipal solid waste (MSW), commercial and industrial waste, hospital/medical/infectious waste, sewage sludge, other solid waste), biomass, plastics,[1] tires, and organic contaminants in soils and oily sludges to useful products such as energy, fuels and chemical commodities.[2] As a result of recent market trends, especially with respect to plastics recycling, the EPA has received several inquiries about regulations under CAA section 129 for solid waste incineration units and the applicability of such regulations to pyrolysis and gasification units for a variety of process and feedstock types. Based on these requests and the differences in language pertaining to pyrolysis among the CAA section 129 rules,[3] the Agency believes that there is considerable confusion in the regulated community regarding the applicability of CAA section 129 to pyrolysis and gasification units. On August 31, 2020, the EPA proposed various revisions to section 129 regulations for ''other solid waste incineration units'' (OSWI), including a proposal to revise the definition of ''municipal waste combustion (MWC) unit'' to remove the reference to ''pyrolysis/combustion units'' (85 FR 54178). In the proposal, the EPA indicated that pyrolysis units do not involve the combustion of solid waste but may combust uncontained gases and that the OSWI rule should not apply to such units (85 FR at 54187). The EPA received significant comments on the proposal regarding the removal of the reference to ''pyrolysis/combustion units.'' In light of these comments and what appear to be on-going questions about the regulation of pyrolysis and gasification units, the EPA has determined that issuance of this ANPRM is an efficient mean for gaining a comprehensive understanding of these units to aid in potential development of future regulations or changes to existing CAA section 129 regulations pertaining to pyrolysis and gasification units.***

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II. Background

A. What are pyrolysis and gasification units?

The CAA does not define pyrolysis or gasification. The EPA has treated pyrolysis and gasification differently under some CAA section 129 rules. These rules apply to various categories of solid waste incineration units (see discussion in section II.B of this preamble).***

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1. Pyrolysis Units

Pyrolysis is a process where materials are thermally decomposed or rearranged under process conditions where extremely little to no oxygen is present.***

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2. Gasification Units

Gasification is a process of converting feed materials (primarily carbonaceous) into syngas (carbon monoxide and hydrogen) and carbon dioxide. The materials are gasified when they react with controlled amounts of oxygen or steam at high temperatures (greater than 700°C). Oxygen (as air, concentrated oxygen, or steam) is added in small amounts to maintain a reducing (i.e., oxidation or combustion-preventing) atmosphere, where the quantity of oxygen available is less than the stoichiometric ratio (i.e., amount needed for complete combustion of the feed material).***

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B. What is the regulatory background for pyrolysis and gasification units?

As noted previously, there is some difference in the treatment of pyrolysis units among the EPA's existing CAA section 129 rules. CAA section 129 relates to standards for various categories of solid waste incineration units. Some of the EPA's CAA section 129 rules do not mention pyrolysis or gasification at all, while others contain specific language applicable to certain types of units or processes.***
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<u>Regarding Applicability of New Source Performance Standards (NSPS) Subpart AAAA</u>

IDEM, OAQ is providing the following updated federal rule applicability determination for NSPS Subpart AAAA:

The requirements of the New Source Performance Standard for Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modifications or Reconstruction is Commenced After June 6, 2001, 40 CFR 60, Subpart AAAA and 326 IAC 12, are not included in the permit for the source for the following reasons:

(i) The gasifier trains (GT-1, GT-2, and GT-3), FT Reactor, and syncrude upgrading section will not include combustion or pyrolysis of the Feedstock materials and would not be considered a "pyrolysis/combustion unit" or "municipal waste combustion unit" as defined in 40 CFR 60.1465. The processes will "break down" and convert Feedstock materials into diesel or jet fuel using a two-step thermochemical process of steam-reforming gasification in an oxygen-deficient atmosphere (producing syngas) and Fischer-Tropsch

(FT) synthesis (producing "syncrude" FT liquids that are further upgraded and refined to diesel or jet fuel). The gasification process will not combust the Feedstock materials (i.e., no direct flame will be applied to the Feedstock materials in the gasifier, nor will a flame be propagated as a result of the heating).

(ii) The flare (FLA) would not be considered a “municipal waste combustion unit” as defined in 40 CFR 60.1465, since the gas that may be combusted from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during periods of startup and shutdown would not be considered a "municipal solid waste". Fulcrum Centerpoint provided IDEM, OAQ with a site-specific "self-determination" under 40 CFR 241.3(b) that determined that the Feedstock material (derived from MSW that is considered a Non-Hazardous Secondary Material (NHSM)) would be a non-waste if it were used as a fuel or ingredient in a combustion unit at the proposed biorefinery.

(iii) The utility boiler (BOIL) would not be subject to the requirements of 40 CFR 60, Subpart AAAA, since it will combust syngas equivalent to greater than 250 tons per day of feedstock to the gasification trains.

This federal rule applicability determination for the gasifier trains is consistent with the U.S. EPA Determination from Douglas K. McDaniel (U.S. EPA) to Patrick D. Traylor (Hogan and Hartson, LLP, on behalf of Fulcrum BioEnergy, Inc.) listed on the Applicability Determination Index (ADI) (https://cfpub.epa.gov/adi/) under the title, "Conversion of Post-Sorted Municipal Solid Waste Feedstock", ADI Control Number 1000019 (dated March 30, 2010).

Regarding Applicability of New Source Performance Standards (NSPS) Subpart Eb

IDEM, OAQ is providing the following updated federal rule applicability determination for NSPS Subpart Eb:

The requirements of the New Source Performance Standard for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996, 40 CFR 60, Subpart Eb and 326 IAC 12, are not included in the permit for the source, because none of the on-site facilities are a *municipal waste combustor*, as defined in 40 CFR 60.51b, for the following reasons:

(i) The gasifier trains (GT-1, GT-2, and GT-3), FT Reactor, and syncrude upgrading section will not include combustion or pyrolysis of the Feedstock materials and would not be considered a “pyrolysis/combustion unit” or “municipal waste combustor” as defined in 40 CFR 60.51b. The processes will “break down” and convert the Feedstock materials into diesel or jet fuel using a two-step thermochemical process of steam-reforming gasification in an oxygen-deficient atmosphere (producing syngas) and Fischer-Tropsch (FT) synthesis (producing "syncrude" FT liquids that are further upgraded and refined to diesel or jet fuel). The gasification process will not combust the Feedstock materials (i.e., no direct flame will be applied to the Feedstock materials in the gasifier, nor will a flame be propagated as a result of the heating).

(ii) The flare (FLA) would not be considered a “municipal waste combustion unit” as defined in 40 CFR 60.51b, since the gas that may be combusted from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during periods of startup and shutdown would not be considered a "municipal solid waste". Fulcrum Centerpoint provided IDEM, OAQ with a site-specific "self-determination" under 40 CFR 241.3(b) that determined that the Feedstock material (derived from MSW that is considered a Non-Hazardous Secondary Material (NHSM)) would be a non-waste if it were used as a fuel or ingredient in a combustion unit at the proposed biorefinery.

(iii) The utility boiler (BOIL) would not be considered a “municipal waste combustion unit” as defined in 40 CFR 60.51b, since the FT Reactor purge gas that may be combusted in the utility boiler would not be considered a "municipal solid waste". The FT Reactor purge gas will consist of unreacted syngas produced from the gasification of the Feedstock material. Fulcrum Centerpoint provided IDEM, OAQ with a site-specific "self-determination" under 40 CFR 241.3(b) that determined that the Feedstock material (derived from MSW that is considered a Non-Hazardous Secondary Material (NHSM)) would be a non-waste if it were used as a fuel or ingredient in a combustion unit at the proposed biorefinery.

This federal rule applicability determination for the gasifier trains is consistent with the U.S. EPA Determination from Douglas K. McDaniel (U.S. EPA) to Patrick D. Traylor (Hogan and Hartson, LLP, on behalf of Fulcrum BioEnergy, Inc.) listed on the Applicability Determination Index (ADI) (https://cfpub.epa.gov/adi/) under the title, "Conversion of Post-Sorted Municipal Solid Waste Feedstock", ADI Control Number 1000019 (dated March 30, 2010).

Regarding Applicability of National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart JJJJJJ

IDEM, OAQ is providing the following updated federal rule applicability determination for NESHAP Subpart JJJJJJ:

The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ are not included in the permit for the one (1) utility boiler, identified as BOIL, because it meets the definition of a *gas-fired boiler*, as defined by 40 CFR 63.11237, which is specifically excluded from the the requirements of 40 CFR 63, Subpart JJJJJJ under 40 CFR 63.11195(e). The utility boiler will only burn natural gas and purge gas from the FT Reactor, which are both considered *gaseous fuels*, as defined by 40 CFR 63.11237. The definitions of *gas-fired boiler* and *gaseous fuels* are provided below:

> *Gas-fired boiler* includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or for periodic testing, maintenance, or operator training on liquid fuel. Periodic testing, maintenance, or operator training on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.
>
> *Gaseous fuels* includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

This federal rule applicability determination for the utility boiler is consistent with the U.S. EPA Determination from David B. Conroy (U.S. EPA) to Stephen Armstrong (MSW Power Corporation) listed on the Applicability Determination Index (ADI) (https://cfpub.epa.gov/adi/) under the title, "Energy Recovery and Syngas Exemption Request for a Gasification Unit", ADI Control Number M140002 (dated December 4, 2012).

Regarding Non-Hazardous Secondary Material (NHSM) Non-Waste Determination

IDEM, OAQ understands that commenters have concerns regarding whether the "self-determination" under 40 CFR 241.3(b) is sufficient to assure the feedstock is not municipal solid waste. U.S. EPA has expressed concern that if not conducted correctly the self-determination could result in a violation of the FESOP permit. EPA requested that IDEM provide additional information in the permit record to support this conclusion, and/or revise the permit. Additionally, EPA requested that IDEM include as part of the permit record a copy of the facility’s NHSM non-

waste determination documentation or other basis upon which the non-waste determination is being made.

EPA published a document "Non-Hazardous Secondary Material (NHSM) Regulations 40 CFR Part 241 Guide For Waste/Non-Waste Determinations – Guide for Waste/Non-Waste Determinations". The document sets forth the following (emphasis added as italic text):

> The intended audience for this guide includes:
> - The regulated community, including NHSM generating facilities and owners/operators of combustion units intending to combust NHSM.
> - U.S. Environmental Protection Agency (EPA) officials with oversight responsibility for the NHSM rules.
> - State, interstate, and local air agency permitting and enforcement officials.
> - Tribal officials
>
> The recommended method for making a non-waste determination is the site-specific "self-determination" done by the facility that generates or combusts the NHSM, since the NHSM regulations are self-implementing. For a self-determination, the generator or combustor of the NHSM at that site is responsible for making the non-waste determination.
>
> ******
> What are the roles and authorities of states in NHSM implementation?
> The NHSM Rule is definitional in nature; it does not contain recordkeeping, monitoring, or other implementation requirements. *Those requirements are contained within the applicable CAA rules: Commercial and Industrial Solid Waste Incineration Units (CISWI), and National Emission Standards for Hazardous Air Pollutants (NESHAP) for major and area source boilers.*
>
> As a result, state and local air programs can play an integral role in ensuring that sources combusting NHSMs have identified whether those materials are wastes or non-wastes consistent with the 40 CFR part 241 standards through facility inspection, air permitting, and review of the required applicability and combustion records. If states have taken delegation of these CAA rules, they have authority to take enforcement actions against facilities that improperly designate or improperly keep records on whether their fuel is solid waste or not.
>
> While states can verify NHSM waste/non-waste self-determinations, *states do not have the authority to provide NHSM waste/non-waste determinations because the air regulations rely on the federal definition of solid waste (RO 14896).* We recommend that state air programs coordinate with EPA regional solid waste contacts for NHSM waste/non-waste determinations.

Fulcrum has submitted documentation that the requirements of 40 CFR Part 241, Subpart B [Identification of Non-Hazardous Secondary Materials That Are Solid Waste When Used as Fuels or Ingredients in Combustion Units] were followed when self-determining that the Feedstock would be a non-waste if it were used as a fuel or ingredient in a combustion unit at the proposed biorefinery. EPA explicitly precludes from states the authority to make a NHSM waste/non-waste determination. IDEM, OAQ does not have the authority to make a determination regarding the validity and accuracy of the information contained in the site-specific "self-determination" Furthermore, the responsibly for making the self-determination is the responsibility of the generator or combustor. Therefore, no further documentation in the permit record is necessary.

If it is determined that Fulcrum's designation of the feedstock as a non-waste was improper, IDEM, OAQ will take appropriate enforcement action.

A copy of the NHSM non-waste self-determination provided by Fulcrum is included as additional information for the permit application and is available for public review via IDEM's Virtual File Cabinet (VFC) at: https://vfc.idem.in.gov/DocumentSearch.aspx.

Regarding 1 of 28 Listed Source Categories (Municipal Incinerators)

As explained in the previous subsections above, the proposed biorefinery will not burn, combust, or incinerate municipal solid waste.

Therefore, the proposed biorefinery would not be classified as the listed source category of "municipal incinerators capable of charging more than 50 tons of refuse per day" specified under 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g)(8), or 326 IAC 2-7-1(22)(B)(viii).

General Statement 12 - Public Hearing

Many commenters requested that IDEM, OAQ conduct a public hearing regarding the draft New Source Construction and FESOP for Fulcrum Centerpoint, LLC.

IDEM Response to General Statement 12 - Public Hearing

On March 31, 2022, IDEM, Office of Air Quality (OAQ) posted a notice on IDEM's website (https://www.in.gov/idem/public-notices/), stating that Fulcrum Centerpoint, LLC, had applied for a New Source Construction and FESOP to construct and operate a new stationary biorefinery. The notice also stated that IDEM, OAQ proposed to issue a New Source Construction and FESOP for this operation and provided information on how the public could review the proposed 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 permit should be issued as proposed.

On March 31, 2022, IDEM, OAQ also posted a notice on IDEM's website (https://www.in.gov/idem/public-notices/), stating that IDEM, OAQ would hold a public hearing on April 27, 2022, to discuss the draft New Source Construction and FESOP for Fulcrum Centerpoint, LLC. The notice provided information on how the public could attend the public hearing, provided information for citizens that needed reasonable accommodations to participate in this event, including accommodations for persons with speech or hearing difficulties, and how the public could review and provide comments on the proposed permit and other documentation. Finally, the notice informed interested parties that the public notice period would end on Monday, May 2, 2022.

On April 27, 2022, from 5:30 p.m. to 7:10 p.m., Central Time, IDEM, OAQ conducted a public hearing regarding the Fulcrum Centerpoint draft New Source Construction and FESOP. The public hearing was well attended and received coverage from local television and newspapers.

On May 2, 2022, IDEM, OAQ had a notice posted on IDEM's website (https://www.in.gov/idem/public-notices/) informing interested parties that the public notice period was extended an additional 14 days and would end on Monday, May 16, 2022.

U.S. EPA Comments Received on Draft New Source Construction and FESOP and IDEM Responses

On March 11, 2022, U.S. EPA, submitted the following comments to IDEM, OAQ on the draft FESOP Renewal.

U.S. EPA Comment 1:

Dear Ms. Acker:

This letter is in regard to Indiana Department of Environmental Management's (IDEM's) new source construction and Federally Enforceable State Operating Permit for Fulcrum Centerpoint, LLC – permit number 089-44042-00660. The permit would allow Fulcrum Centerpoint, LLC to construct and operate a biorefinery at 6200 Industrial Highway, Gary, Indiana 46406 in Lake County. The U.S. Environmental Protection Agency (EPA) reviewed the draft permit and associated permit files.

EPA is committed to advancing environmental justice and incorporating equity considerations into all aspects of our work. This commitment includes improving our assessment and consideration of the impacts of permits on communities already overburdened by pollution. EPA welcomes IDEM's partnership in this important effort.

EPA has determined that the proposed location of the facility raises potential environmental justice concerns. Data from EPA's environmental justice screening tool, EJScreen, illustrate the severity of pollution and health impacts facing the community living in proximity to the Fulcrum Centerpoint, LLC site.[1] The neighborhoods around the proposed facility have some of the highest levels in the state for many environmental justice indexes reported by EJScreen. EJScreen is a useful first step in understanding communities that may have environmental justice concerns.

The values for all 12 environmental justice indexes for the area surrounding the proposed facility exceed the 90th percentile in the state. This area includes the eastern portions of East Chicago and Hammond, and the western portion of Gary. The environmental justice indexes include particulate matter of less than 2.5 microns in diameter, ozone, diesel particulate matter, air toxics cancer risk, air toxics respiratory hazard, traffic proximity, lead paint, and Superfund site proximity. EJScreen also indicates significant health disparities (low life expectancy and the prevalence of heart disease and asthma) in the area, exceeding the 80th percentile. The population living in the area around the proposed facility is significantly comprised of people of color, linguistically isolated households (Spanish language), those with low income, those with less than a high school education, and a high unemployment rate.[2]

EPA acknowledges the work IDEM has already undertaken on this permitting action, including providing enhanced opportunities for public participation by holding a public hearing on April 27, 2022 in consideration of the significant public interest, and by extending the public comment period to May 16, 2022. We also acknowledge IDEM's standard practice of making application materials and other permit records readily available online, which can improve accessibility and transparency to the public.

Our permit comments are included in the attachment to this letter. We appreciate that IDEM has been working with Fulcrum to address some of the identified issues. In consideration of environmental justice and equity concerns, we also provide the following recommendations:

- We recommend that IDEM conduct an environmental justice analysis of appropriate scope to inform the permitting decision. The analysis should include an EJScreen analysis, input from the affected community to identify their concerns, an evaluation of existing environmental data, and an evaluation of existing demographic and public health data about the community. The analysis should evaluate the potential effects that the permitting action will have on the community, and the degree to which these effects will be disproportionately high and adverse. The analysis should further discuss mitigations the permit requires to address any identified effects. EPA will

assist and support IDEM as needed, consistent with our commitment to environmental justice and to effectively implement Title VI of the Civil Rights Act of 1964.

- We recommend that IDEM conduct a cumulative impact analysis to determine the source's potential impact on the affected communities. A cumulative impact analysis will demonstrate that the permit will be protective of health and the environment in those communities. We note that the proposed source will be located in an area that has numerous other sources in the vicinity, suggesting that a cumulative impact analysis could be appropriate for this permit action.[3] EPA will assist and support IDEM as needed in preparing the analysis.

- We recommend that IDEM consider opportunities to address disproportionately high and adverse effects that extend beyond the scope of the air permitting decision that utilize a whole-of-government approach by working with the company and local officials to reduce impacts on the surrounding neighborhood.

- We recommend that, if the proposed project is permitted, data regularly generated by Fulcrum Centerpoint, LLC to comply with the permit be made publicly available on an easily accessible website. The transparency of such data will promote public engagement and help build trust among all stakeholders.

Finally, because of the environmental conditions already facing this community, and the potential for additional disproportionate and adverse impacts based on race, national origin, or other protected class, the siting of this facility may raise civil rights concerns. It is important, therefore, that IDEM assess its obligations under civil rights laws and policies.

Thank you again for the opportunity to work with you on this draft permit. EPA remains committed to working together with IDEM to address our shared environmental priorities, advance equity, and reduce potential environmental and health impacts on communities such as this one.

Sincerely,

John Mooney
Director
Air and Radiation Division

Footnotes:
1 EJScreen is a mapping and screening tool that provides EPA with a nationally consistent dataset and approach for combining and comparing environmental and demographic indicators.
2 Data from an EJScreen standard report and an EJScreen American Community Survey (ACS) Summary Report for a 3-mile radius ring centered at 6200 Industrial Highway, Gary, Indiana.
3 Based on EPA's Enforcement and Compliance History Online (ECHO) database (https://echo.epa.gov), there are approximately 50 Title V sources within 5 miles of Fulcrum Centerpoint's street address.

IDEM Response to U.S. EPA Comment 1:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit Renewal
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 4 - Fugitive Dust and Particulate Matter

- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 9 - Pollution Control, Compliance Determination/Monitoring, and Stack Testing

No changes to the draft permit were made as a result of this comment.

U.S. EPA Comment 2:

1) Page 20 of the Technical Support Document (TSD) states the source is subject to the Lake County Fugitive Particulate Matter requirements of 326 IAC 6.8-10, because the source-wide unlimited potential to emit (PTE) of fugitive particulate matter (PM) is 5 tons per year or more.

   a. The permit does not include the associated particulate matter emission limitations of 326 IAC 6.8-10-3. We request that IDEM review the permit and add the requirements, as appropriate.

   b. Page 22 of the TSD indicates the Permittee shall achieve the limits of 326 IAC 6.8-10-3 by controlling fugitive particulate matter emissions according to the Fugitive Dust Control Plan (FDCP) included as Attachment A to the permit. We request that IDEM review the FDCP and add appropriate control, monitoring and response measures, as needed, in consideration of the following:

      i) The FDCP does not contain control or monitoring related to the potential for fugitive emissions from open-bodied trucks (if used) for inplant transportation of slag and feedstock material that may be needed to comply with 326 IAC 6.8-10-3(6)(A). Examples of measures may include adhering to posted facility speed limits, or a requirement for open-bodied trucks to engage tarps during inplant transportation.

      ii) The FDCP does not contain control or monitoring related to the potential for fugitive emissions escaping from the feedstock storage building structures (e.g., truck entry/exit doorways) that may be needed to comply with 326 IAC 6.8-10-3(7)(D).

      iii) The FDCP does not contain control or monitoring related to fugitive dust generated from slag handling/loading that may be needed to comply with 326 IAC 6.8-10-3.

IDEM Response to U.S. EPA Comment 2:

Below are IDEM's responses to each of the U.S. EPA comments:

a. Section C of the permit is revised to include the requirements of 326 IAC 6.8-10 (Lake County Fugitive Particulate Matter) and 326 IAC 6.8-11 (Lake County Particulate Matter Contingency Measures) as Conditions C.6 and C.7, respectively. All remaining conditions in Section C are renumbered accordingly. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

b. Regarding U.S. EPA comments on the Fugitive Dust Control Plan (FDCP):

   i). Fulcrum Centerpoint, LLC, provided a Site Operating Plan (SOP) in its solid waste processing permit application (see VFC document # 83257441) that indicated that feedstock will be delivered to the facility by trucks with enclosed trailers, which will prevent the escape or spillage of feedstock during transport and while on-site.

The City of Gary, Zoning Department, issued a zoning verification letter to Fulcrum Centerpoint, LLC (see VFC document #83302394, p. 92-125 of 184), specifying that the biorefinery operation would be required to comply with the City of Gary Municipal Code (MC), Chapter 34 (Solid Waste), which can be found on the internet at: https://library.municode.com/in/gary/codes/code_of_ordinances?nodeId=PTIGEOR_CH34SOWA_ARTIILICO

The City of Gary Municipal Code (MC), Chapter 34 (Solid Waste) contains provisions aimed at eliminating litter, refuse, and rubbish within city limits, including provisions for non-public locations.

The Fugitive Dust Control Plan (FDCP) (included as Attachment A of the permit) is revised to specify that delivery and shipping trucks will be required to adhere to a posted facility speed limit of 20 miles per hour. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

ii). Fulcrum Centerpoint, LLC, provided a Site Operating Plan (SOP) in its solid waste processing permit application (see VFC document # 83257441) that indicated that feedstock will be unloaded into one (1) of the three (3) separate Feedstock storage buildings, which are each enclosed with solid walls and doors that will be closed when the facility is not in operation or when feedstock deliveries are not being made.

The Fugitive Dust Control Plan (FDCP) (included as Attachment A of the permit) is revised to specify that feedstock will be unloaded into one (1) of the three (3) separate Feedstock storage buildings, which are each enclosed with solid walls and doors that will be closed when the facility is not in operation or when feedstock deliveries are not being made. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

iii). Slag is the silicon dioxide and metal oxide mixture left over as a by-product of extracting metal from its ore during the smelting process. What is labeled as "slag" in the permit application is waste material generated from non-gasifiable materials (e.g., sand, rocks, aluminum foil, etc.) that are entrained in the syngas stream exiting the three (3) steam reformers and the three (3) carbon trim cells. This waste material does not meet the definition or description of slag. Nor, does the process via which the waste material is generated involve removal of metal from its ore. Fugitive PM emissions will be generated as the waste material is loaded onto trucks from roll-off or hopper bins.

The Fugitive Dust Control Plan (FDCP) (included as Attachment A of the permit) is revised to include slag handling activities as a potential source of fugitive dust emissions and to require that the transfer of waste material comply with the requirements of 326 IAC 6.8-10-3(9). See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

U.S. EPA Comment 3:

2) To assure compliance with the various synthetic minor PM, PM10, PM2.5 limits of conditions D.1.1(a), D.1.2(a) and Lake County particulate emission limits of D.1.4(a), condition D.1.10 requires that baghouses shall be in operation and controlling emissions from various specified emission units.

a. To support condition D.1.10, condition D.1.21 requires daily visible emissions (VE) notations of the feedstock storage buildings, feedstock dryers, ash silos, and bed media silos stack exhausts to determine if they are “normal” or “abnormal”. It is unclear how condition D.1.21 provides reasonable assurance that the baghouses are operating properly, sufficient to yield reliable data that are representative of the source’s compliance with condition D.1.10. We request that IDEM review the permit to ensure it contains sufficient monitoring per 326 IAC 2-8-4(3)(A)(ii) and revise the permit, as needed, in consideration of the following:

   EPA has noted that, in certain situations, monitoring for VE using certain Method 22-like observation techniques can be a useful and effective indicator of fabric filter performance, while acknowledging its lower sensitivity compared to other monitoring techniques (see EPA’s Draft Compliance Assurance Monitoring Technical Guidance Document Appendix B, Revision 1, January 2005). Method 22 is a qualitative technique that checks only the presence or absence of VE, rather than determining opacity levels.

   Method 22 is used in conjunction with emission standards or work practices in which no VE is the stated goal (EPA Visible Emissions Field Manual, EPA Methods 9 and 22, December 1993). In the aforementioned January 2005 document, EPA provided a non-exhaustive list of monitoring approaches used in conjunction with fabric filters that may provide a reasonable assurance of compliance. It describes an example compliance assurance strategy that employs either daily Method 9 opacity readings, or daily VE observations by a trained observer using Method 22-like VE/no VE observation techniques (Approach No. 1a). The document highlights the appropriate use of the VE/no VE criterion for monitoring using this approach, stating "For situations where no visible emissions are the norm, a technique focused towards identifying a change in performance as indicated by *any visible emission* is a useful and effective technique. The use of the *visible/no visible emissions technique* reduces the need for onsite certified RM 9 observers." (*emphasis added*).

   Condition D.1.21 requires VE notations to determine if emissions are “normal” or “abnormal” with respect to the prevailing (or expected to prevail) visible emission conditions for the specific process, based upon a trained employee’s familiarity with such “normal” conditions. It is unclear whether the compliance monitoring approach in this case, which expects employees to reliably assess the level of VE in comparison to a potentially nonzero reference amount of VE, is practicably enforceable and sufficient to provide reasonable assurance that the baghouses are operating properly per condition D.1.10 and ultimately as part of the strategy to assure compliance with conditions D.1.1(a), D.1.2(a), and D.1.4(a).

b. We recommend that IDEM and the source consider the use of bag leak detection systems (BLDS) to comply with condition D.1.10. BLDS may be used to track baghouse activity and establish pre-set level alarms to notify operators. BLDS may help ensure that the baghouses are operating properly to control emissions, help to proactively identify developing bag leaks and avoid baghouse failures, and help ensure compliance with the emission limits of D.1.1(a), D.1.2(a) and D.1.4(a).

IDEM Response to U.S. EPA Comment 3:

The permit is revised to include a new Condition D.1.21 with Bag Leak Detection System (BLDS) requirements for the feedstock storage buildings (FDSTG-1, FDSTG-2, and FDSTG-3), feedstock dryers (DRYER-1, DRYER-2, and DRYER-3), ash silos (ASH1, ASH2, and ASH3), and bed media silos (BMS1, BMS2, and BMS3) and to remove the previous Condition D.1.21 (Visible Emission Notations). See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

U.S. EPA Comment 4:

3) The TSD, Appendix A indicates that SO_2 emission factors for purged syngas firing in the utility boiler BOIL and flare FLA rely on estimates based on Fulcrum Centerpoint design data and estimates of hydrogen sulfide content. We note that the permit does not appear to include requirements related to proper operation or monitoring of the Sulfur Removal Unit SRU, which is used to remove hydrogen sulfide from the syngas. Absent enforceable permit requirements related to the SRU, the source may emit more SO_2 from BOIL and FLA than assumed in TSD, Appendix A. We request that IDEM evaluate whether additional permitting requirements are necessary to assure that the source will comply with applicable SO_2 emission limits.

IDEM Response to U.S. EPA Comment 4:

The permit is revised to include a new Condition D.1.23 that requires the Permittee to sample and analyze the exhaust gas stream from the Sulfur Removal Unit (SRU) once per day in order to determine the H_2S content and to include instrument calibration requirements. All subsequent Section D.1 conditions and condition references are renumbered accordingly. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

The vendor guaranteed H2S concentration in the SRU exhaust gas (CO2 vent) is 10 ppmv. A H2S concentration value of 20 ppmv is used in the permit as the response step threshold value. The potential to emit (PTE) calculations for the SRU are updated, assuming that the SRU exhaust gas will have a worst case H2S concentration of 20 ppmv (see Appendix A of this ATSD). Based on the updated calculations, the SRU has a PTE of H2S of 10.47 tons/year.

U.S. EPA Comment 5:

4) It is unclear whether the permit contains sufficient requirements to assure compliance with the hazardous air pollutant (HAP) synthetic minor limits of C.1(a)(4) and C.1(a)(5), specifically regarding HAP emissions from the FT Reactor, utility boiler BOIL, and flare FLA. We request IDEM evaluate the proposed monitoring requirements and provide additional justification and/or revise the permit, in consideration of the following:

Condition D.1.15 requires a one-time analysis of the purge gas stream from the FT Reactors for volatile organic compound (VOC) and HAP content and requires the Permittee to submit updated VOC and HAP calculations for the FT Reactor, utility boiler, and flare FLA to IDEM. It is unclear how this requirement provides reliable data from the relevant time period that is representative of the source's compliance with the synthetic minor limits, per 326 IAC 2-8-4(3)(A)(ii).

We request that IDEM assess the potential for variability in HAP emissions based on the potential for variability in the feedstock content, and further justify why the one-time VOC and HAP analysis of condition D.1.15 is sufficient or revise the permit accordingly. We request that IDEM consider whether additional permit requirements related to acceptable feedstock content, associated work practices, periodic feedstock and/or purge gas stream content monitoring, HAP stack testing and/or recordkeeping are appropriate to assure compliance with HAP synthetic minor limits.

IDEM Response to U.S. EPA Comment 5:

Condition D.1.15 of the permit is revised to include the requirement to sample and analyze the purge gas stream from the FT Reactor for HAP content once per week and to include instrument calibration requirements. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

Feedstock for the proposed biorefinery will be produced at separately permitted Feedstock Processing Facilities (FPFs), which will use commercially proven processing equipment to shred and sort municipal solid waste (MSW) with sequential steps recovering valuable recyclable materials, removing unwanted components of the waste stream, and improving the physical and compositional attributes of the Feedstock for diesel/jet fuel production in the biorefinery.

On December 21, 2021, Fulcrum Centerpoint, LLC, submitted a solid waste processing permit application (see VFC document # 83257441, pages 70-71 of 192) to IDEM Office of Land Quality (OLQ) that specified that the Feedstock delivered to the proposed biorefinery from the FPFs shall not contain, nor shall the proposed biorefinery accept the following prohibited materials:

- Regulated Hazardous Waste;
- Polychlorinated Biphenyl (PCB) Waste;
- Bulk or Non-containerized Liquid Waste;
- Sludges and Other Wastewater Treatment Solids;
- Asbestos and asbestos containing materials; and
- Source Separated Special Waste (Used tires, medical waste, used oil and filters, batteries).

The FPFs will use industry best practices and procedures to detect, prevent and control the receipt of prohibited materials.

The FPF processes, practices, and procedures described above will help assure that the Feedstock content variability is minimized.

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 10 - Feedstock Materials

U.S. EPA Comment 6:

5) The TSD includes IDEM's justification for why New Source Performance Standards (NSPS) Subparts AAAA and Eb are not included in the permit. EPA requests that IDEM provide additional justification and/or revise the permit, as follows:

   a. IDEM states that none of the on-site facilities are a *municipal waste combustion unit* or *municipal waste combustor* as defined in NSPS Subparts AAAA and Eb, respectively. IDEM cites a March 30, 2010, EPA applicability determination (ADI Control Number 1000019) for a Nevada facility to support its rationale related to the syngas gasification process.

   IDEM states the utility boiler BOIL is not subject to Subpart AAAA because it will combust primarily natural gas that is supplemented by the purge gas stream. However, this explanation does not clearly establish why the combustion of syngas purge gas in utility boiler is not considered a *municipal waste combustion unit* or *municipal waste combustor* as defined in Subparts AAAA and Eb, respectively. It appears IDEM may be referring to the exemption for co-fired combustors at 40 CFR 60.1020(g) (and similar exemption at 40 CFR 60.50b(j) for Subpart Eb). Although the permit specifies the maximum heat input capacities for natural gas and purge gas to the utility boiler, respectively, it is unclear whether the permit includes enforceable requirements sufficient to limit (in practice) the combustion of municipal solid waste to 30 percent of the total fuel input by weight, recorded on a quarterly basis, as required by these provisions. We request that IDEM further clarify this portion of its justification, and/or revise the permit if needed.

b. IDEM states the feedstock that is converted to syngas in the gasifier is not considered municipal solid waste since it qualifies as a Non-Hazardous Secondary Material (NHSM) under 40 CFR 241, Subpart B. We request that IDEM provide additional information in the permit record to support this conclusion, and/or revise the permit, in consideration of the following:

40 CFR 241.3 sets forth specific criteria for a municipal solid waste to be appropriately considered a non-waste fuel. Specifically, municipal solid waste can be considered a non-waste fuel only if it has been (1) adequately processed, and (2) meets the legitimacy criteria in 40 CFR 241.3(d)(1). [40 CFR 241.3(b)(4)]

Determining whether a NHSM is a solid waste or not when it is combusted is key to understanding which CAA requirements apply to the unit that combusts the NHSM. Units combusting an NHSM that is a solid waste are subject to the requirements of CAA section 129 (e.g., NSPS Subparts AAAA and Eb), while units that combust an NHSM that is not a solid waste are subject to regulations promulgated under CAA section 112. CAA section 129 applies to solid waste combustion units such as commercial and industrial solid waste incinerators, while CAA section 112 applies to other types of units, such as boilers. If a combustion unit subject to CAA section 112 burns an NHSM that is a solid waste under the Resource Conservation and Recovery Act, then that unit will be in violation of its CAA permit. Therefore, it is critically important that non-waste determinations be done correctly. NHSMs other than traditional fuel, clean cellulosic biomass, or categorical non-waste require a determination that the NHSM is not a solid waste when burned as a fuel and meets the legitimacy criteria in the regulations. The recommended method for making a non-waste determination is the site-specific "self-determination" done by the facility that generates or combusts the NHSM, since the NHSM regulations are self-implementing. See EPA guide "Non-Hazardous Secondary Material (NHSM) Regulations 40 CFR Part 241. Guide for Waste/Non-Waste Determinations" for additional information. https://www.epa.gov/sites/default/files/2021-05/documents/nhsm_guide_5_26_2021.pdf

Furthermore, the preamble discussion in the 2011 final rule "Identification of Non-Hazardous Secondary Materials That Are Solid Waste" includes a discussion about syngas as an NHSM (see 76 FR 15538, March 21, 2011). It states that "Synthesis gas (or syngas as it is commonly referred) produced from the gasification of solid waste is another material that can also meet the requirements of a fuel product produced from the processing of discarded non-hazardous secondary materials, *provided the syngas has been adequately processed to remove contaminants*." (*emphasis added*).

To support a clear permit record, we request that IDEM include as part of the permit record a copy of the facility's NHSM non-waste determination documentation or other basis upon which the non-waste determination is being made.

The above comments regarding the applicability of NSPS Subpart AAAA and NSPS Subpart Eb are contingent on the combusted materials being sufficiently documented to meet the requirements of 40 CFR 241.3(b)(4) and/or the other requested clarifications/permit revisions above.

IDEM Response to U.S. EPA Comment 6:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 11 - Incineration

No changes to the draft permit were made as a result of this comment.

U.S. EPA Comment 7:

6) Page 2 of the TSD states that fugitive emissions are not counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability, due in part to the conclusion that this type of operation is not one of the twenty-eight listed source categories under 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B).

   326 IAC 2-2-1(ff)(1) includes the listed source category "municipal incinerators capable of charging more than 50 tons of refuse per day." Also see 326 IAC 2-3-2(g)(8) and 326 IAC 2-7-1(22)(B)(viii). To support a clear permit record, we request that IDEM provide justification for why the source is not considered a municipal incinerator under the above rules, and/or update the permit, if needed.

IDEM Response to U.S. EPA Comment 7:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 11 - Incineration

No changes to the draft permit were made as a result of this comment.

U.S. EPA Comment 8:

7) We request that IDEM confirm that the flare information used in the equations of Condition D.1.9(a) and (b) refers only to the gasifier train flare FLA (not the truck loadout system flare LOAD). We also request that IDEM confirm whether the heat input used for the equation term "FSUSD" in the above equations refers to purge gas, natural gas, or both. We recommend that IDEM update the permit accordingly to improve permit clarity.

IDEM Response to U.S. EPA Comment 8:

The information used in the equations of Condition D.1.9(a) and (b) refers only to the gasifier train flare (FLA), not the truck loadout system flare (LOAD). The heat input used for the equation term "FSUSD" in the equations of Condition D.1.9(a) and (b) refers to the VOC emissions from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during periods of startup and shutdown and does not include the heat input to the flare pilot. The flare (FLA) pilot natural gas usage is included in the equation term "F" of Condition D.1.9(a) and (b).

Condition D.1.9 of the permit is revised to provide clarification and to include an updated equation for calculating CO emissions. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

U.S. EPA Comment 9:

8) Condition D.1.7 specifies test methods used to assure compliance with the volatile organic compounds from the wastewater. The permit condition lists particular test methods in significant detail as described below:

   (1) SW-846 Method 5030B (purge and trap) followed by SW-846 Method 8015B with a DB-5 boiling point (or equivalent column), and flame ionization detector, with the detector calibrated with benzene as required by 40 CFR 261*.
   (2) SW-846 Methods 3810, 5030B (followed by 8021B), 8260B, and 9060 as required by 40 CFR 261*.
   (3) U.S. EPA 40 CFR 136 Methods 602, 624, 1624, 625, 1625*.

(4) U.S. EPA 40 CFR 63 Method 305*.
(5) U.S. EPA 40 CFR 60 Method 25D*.

In the event of any conflict, U.S. EPA 40 CFR 60 Method 25D* takes precedence.

Whereas other permit conditions for compliance requirements (see condition D.1.6) do not clearly define the test methods used to assure compliance with all applicable requirements. Condition C.8 of the draft permit contains a general broad statement that, "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."

EPA recommends that IDEM specify the test methods in these conditions in order to provide the public and the permit record a thorough analysis and determination of expected testing methods which will be used to assure compliance with the permit conditions. We understand that upon actual testing, an alternative testing method may be deemed necessary, and the compliance requirements can provide for such an occasion where the Commissioner would need to approve an alternative method than the one specified in the permit.

IDEM Response to U.S. EPA Comment 9:

The proposed permit contains the following requirements related to test methods:

- Conditions D.1.6 and D.1.15 of the proposed permit specify that testing shall be performed *utilizing methods as approved by the Commissioner* and conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). (*emphasis added*)
- Section C - Compliance Requirements of the proposed permit specifies that 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*. (*emphasis added*)

326 IAC 3-6 (Source Sampling Procedures) contains the following requirements related to test methods:

- 326 IAC 3-6-1 (Applicability; test procedures) specifies that the owner or operator of an emissions unit shall conduct emission tests subject to this rule in accordance with any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, *or other procedures approved by the department and U.S. EPA*. (*emphasis added*)
- 326 IAC 3-6-5(d)(1) (Specific testing procedures for volatile organic compounds) specifies that the owner or operator shall conduct volatile organic compounds (VOC) emissions tests in accordance with 40 CFR 60, Appendix A, Method 25*, *or other procedures approved by the department and U.S. EPA*. (*emphasis added*)

For Condition D.1.7 of the proposed permit, IDEM, OAQ approved the use of the test methods in 326 IAC 8-20-7(6) for determining the VOC concentration of wastewater samples, since 326 IAC 3 does not contain specific test methods for determining the VOC concentration of wastewater samples. Indiana state rule 326 IAC 8-20 was approved by U.S. EPA in the Indiana State Implementation Plan (SIP) on February 24, 2010 (see Federal Register 75 FR 8246).

For Conditions D.1.6 and D.1.15, IDEM, OAQ did not specifically list the specific test method(s) to be used, since the permit and 326 IAC 3-6 specify that Permittee may use any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, or 40 CFR 75 or other procedures approved by the department and U.S. EPA.

Condition D.1.7 of the permit is revised to cite to the test methods in 326 IAC 8-20-7(6). See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

U.S. EPA Comment 10:

9) Conditions D.1.2(h) and (i) establish annual NOx and VOC emission limitations applicable to the flare and several other emissions units to avoid PSD, nonattainment NSR, and part 70 permitting applicability. Included as part of this limit are emissions resulting from startup and shutdown during flaring operations. As shown on page 10 of TSD appendix A, the source anticipates flaring during 7 startup events per year at 12 hours per event and during 28 shutdown events per year with each lasting anywhere from 0.25 hours to 12 hours. During the startup scenario, the source anticipates flaring 248,252 pounds of syngas for hour. Annual emissions for all pollutants are calculated based on these assumptions. The hourly emission rate for pollutants flared during startup, calculated using the hourly heat input for flaring after the scrubber and emissions factors in TSD Appendix A page 10, are the following: CO: 334.98 lb/hr; NOx: 73.48 lb/hr; PM/PM_{10}/$PM_{2.5}$: 51.65 lb/hr; SO_2: 289.92 lb/hr.

   a. Condition D.1.9(a) and (b) specifies the method for calculating NOx and VOC emissions. For startup and shutdown emissions, each equation requires the amount of syngas flared during startup and shutdown. However, the permit does not appear to define what startup or shutdown is for this particular process. Other permit conditions that rely on whether startup or shutdown occurs includes conditions D.1.3, D.1.12, D.1.21, and D.1.23. For permit clarity and improved permit enforceability, we request that you define startup and shutdown within the permit.

   b. The flare's PTE is calculated based on the annual amount of gas combusted during startup and shutdown. Although NOx and VOC are limited on an annual basis in conditions D.1.2(h) and (i), the permit does not limit the amount of gas that can be flared during startup or shutdown nor does the permit limit the number and length of each startup and shutdown. Absent enforceable limits on flaring, the source may flare more syngas than assumed in TSD Appendix A, potentially resulting in underestimating the flare's potential PM, PM_{10}, $PM_{2.5}$, SO_2, and CO emissions. We request that you evaluate whether flaring limitations are required to ensure that the source does not trigger more stringent permitting requirements. If you determine that flaring limitations are necessary, we request that you incorporate these emission limitations into the permit with appropriate monitoring, recordkeeping, and reporting to ensure each limit is enforceable as a practical matter.

   c. Given the potential hourly emissions and assumed frequency of startup and shutdown operations, we recommend evaluating the source's permitted impact on ambient air. This evaluation could show that the permit is protective during all allowed operating scenarios, including startups and shutdowns.

IDEM Response to U.S. EPA Comment 10:

Below are IDEM's responses to each of the U.S. EPA comments:

a. Condition D.1.3(a) of the permit is revised to define the terms startup and shutdown. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

b. NOx and VOC emissions are limited on an annual basis in permit Conditions D.1.2(h) and (i) and compliance with these limits shall be determined using the equations in Condition D.1.9(a) and (b). To calculate the NOx and VOC emissions from flaring of emissions from the gasifier trains (GT-1, GT-2, and GT-3) and the FT reactor during periods of startup and shutdown, the equations in Condition D.1.9(a) and (b) include the flare heat input during periods of startup and shutdown (MMBtu/month) and flare emission rates of 0.068 lb of NOx

per MMBtu and 0.14 lb of VOC per MMBtu. The permit contains all necessary testing requirements, control device operating requirements, compliance monitoring requirements, and associated record keeping and reporting requirements to assure that NOx and VOC emissions limitations are enforceable as a practical matter. Additional permit limitations on the amount of gas that can be flared during startup or shutdown and the number and length of each startup and shutdown are not necessary to assure compliance with the NOx and VOC emissions limitations in permit Conditions D.1.2(h) and (i).

The CO limit in Condition D.1.2(j) of the permit is revised to include the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater and to increase the CO limit to 83.69 tons per twelve (12) consecutive month period. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

c. An air quality analysis is required for permits issued under the provisions of 326 IAC 2-2 [Prevention of Significant Deterioration (PSD)]. Since this permit is not being issued under the authority of 326 IAC 2-2 (PSD), an air quality analysis is not required and has not been conducted. No changes to the draft permit were made as a result of this comment.

U.S. EPA Comment 11:

10) Permit conditions E.3.1 and E.3.2 indicate that the listed emission units are subject to the general provisions of NSPS Subpart A and the leak detection and repair program requirements of NSPS Subpart VVa. We wish to highlight that the NSPS general provisions give owners/operators the option to identify leaking equipment using an optical gas imaging instrument instead of leak monitoring as prescribed in 40 CFR part 60, appendix A-7 (i.e., using a Method 21 instrument). This alternative work practice (AWP) is described in 40 CFR § 60.18(g) through (i).

Additional information about the AWP can be found in the Federal Register at https://www.gpo.gov/fdsys/pkg/FR-2008-12-22/pdf/E8-30196.pdf (73 FR 78199, December 22, 2008). EPA assessed that the AWP provides equivalent control as the existing Method 21-based LDAR work practice standards and appears to be less burdensome to implement.

IDEM Response to U.S. EPA Comment 11:

IDEM, OAQ thanks U.S. EPA for highlighting that the NSPS general provisions give owners/operators the option to identify leaking equipment using an optical gas imaging instrument instead of leak monitoring.

U.S. EPA Comment 12:

11) We note the following which appear to be typographical errors. We request IDEM review and update the permit, as needed:

a. Condition D.1.4 specifies particulate matter emission limitations for one feedstock storage emission unit "FDSTG". It appears this is intended to refer to all three feedstock storage buildings FDSTG-1, FDSTG-2, and FDSTG-3. We request that IDEM review condition D.1.4 and update the permit, as needed.

b. Condition D.1.10(a) refers to one baghouse, but there is a baghouse for each of the three feedstock storage buildings, FDSTG-1, FDSTG-2, and FDSTG-3.

IDEM Response to U.S. EPA Comment 12:

Below are IDEM's responses to each of the U.S. EPA comments:

a. Condition D.1.4 of the permit is revised to refer to all three feedstock storage buildings FDSTG-1, FDSTG-2, and FDSTG-3. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

b. Condition D.1.10(a) of the permit is revised to refer to the baghouses for each of the three feedstock storage buildings, FDSTG-1, FDSTG-2, and FDSTG-3. See Appendix B to the ATSD, Proposed Changes to Permit section, for the documented changes to the permit, with deleted language as strikeouts and new language bolded.

Public Comments Received on Draft New Source Construction and FESOP and IDEM Responses

The following public comments were submitted to IDEM, OAQ on the draft FESOP Renewal:

Comment 1:

On April 21, 2022, Lin Kaatz Chary submitted the following comments by email:

I was given your name by Theresa Weaver because I am seeking information regarding the fire that occurred at the Brightmark Energy facility in Ashley, IN on March 14, 2021. I have also been in correspondence with Ms. Ling Tapp who has not been able to help me so I am turning to you.

I started out looking in the Virtual File Cabinet on the IDEM website for any reports on the follow-up to this fire but was unable to find any regarding testing of the air, water or soil, nor any emergency incident reports. I also emailed the fire chief in Ashley asking for any reports they had but he never responded.

I am interested only in what kinds of testing (air, water, soil for example) was done in the area following the fire to see what the extent of air deposition was from the burning materials at the plant. As you know, of course, their primary feedstock is plastic which, as you are also aware, represents a danger of dioxin release as a product of incineration. I am not interested in any proprietary information whatsoever about Brightmark beyond what is publicly available about or can be made publicly available about the cause of the fire.

To my surprise, Ms. Tapp told me that the fire chief did not report the fire to IDEM and thus apparently no testing was carried out. I am hoping that you, as the permit writer, can help me understand the process here. My assumption is that it is the responsibility under the permit requirements that the company, Brightmark, is responsible for filing an emergency incident report when any event of this type occurs. Is this incorrect? If not, what is the purpose of the incident report forms included in the permits and under what circumstances would they be used?

I am also hoping to understand why IDEM would not find it of great importance and urgency even in the absence of a report from Brightmark to do testing in the area to determine the risk to residents in the area. I realize that Ashley is a very small town; is size a factor in deciding whether or not to test in situations such as this? I saw pictures of the fire and read the newspaper reports about it; it was reported as a major fire requiring firefighters from several different cities so it seems clear that it was a significant event and that environmental testing of the area would be a high priority issue, not only for IDEM but for Indiana's State Department of Health and local ATSDR equivalent. As a public health professional, I am very puzzled at the apparent lack of response.

However, I'm also specifically interested today because I really want to better understand the permitting process, in particular the permit renewal process in a situation such as this. I saw that Brightmark applied

for and received a permit renewal only a month following the fire. I did not read the entire 304 pages of the permit application, I admit! From what I could see, however, there was no mention of the fire and its occurrence did not seem to factor into the evaluation of the plant's operation in terms of granting the permit renewal. Can you help me understand from IDEM's perspective the relative importance or non-importance of such an incident in permit renewal process?

My interest in these questions and the data from testing are related to a permit application in Gary, IN where I live for a plant using a very similar process to that of Brightmark's. Fulcrum Centerpoint seeks to build a facility which proposes to use gasification to convert municipal waste comprised of 30% plastic into a precursor of lower-carbon jet fuel.

Unlike the town in which Brightmark is located, however, there are approximately 35,000 people within a 3-mile radius of this new plant, which is also virtually on the shoreline of Lake Michigan. This is also an environmental justice-impacted community which is very concerned about the potential risks associated with siting this new project where proposed, especially as the area is already home to many other significant sources of emissions with serious health implications.

With limited information available to the public due to Fulcrum's confidentiality agreements with IDEM (similar to those of Brightmark's) it has been very difficult for the community to assess the safety and potential risks of this plant. As a result, the incident at Brightmark has raised additional safety concerns because the process and feedstocks are very similar.

The implications of an incident such as the one which occurred in Ashley are significantly more far-reaching and threatening due to several important factors. These include as mentioned earlier, the density of population surrounding the plant, how close the plant is to Lake Michigan which is the drinking water source for millions of people in three states, a major recreational area, and particularly sensitive to air deposition, and finally, not least of all, the location of this plant in an historically disproportionately environmentally impacted community.

Any help you can give me in understanding this situation will most gratefully appreciated. If, as we anticipate, the permit application for Fulcrum is approved, we must make sure that it includes iron-clad reporting requirements for any incidents or fires that may occur that jeopardize the health and well-being of our communities to an even greater extent than the presence of the plant itself. I thank you in advance for your time and attention, and look forward to hearing from you at your earliest convenience (our public hearing is on Thursday, April 27).

IDEM Response to Comment 1:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 5 - Possible Future Violations
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

With respect to comments about the fire that occurred on May 14, 2021, at the Brightmark Plastics Renewal Indiana 2, LLC, plant in Ashley, Indiana, IDEM, OAQ has no information as to the cause of the fire, the types of material(s) involved in the fire, or the steps takes to put out the fire. In addition, IDEM, OAQ is not aware of any testing (air, water, or soil) that was done in the area following the fire.

If a permitted (Part 70 or FESOP) source such as Brightmark has a fire that results in a deviation(s) from any air permit requirement(s) or an exceedance of an air permit limitation(s), then that source would be required to report the deviation(s) and any response steps taken as part of a Quarterly Deviation and Compliance Monitoring Report. If a permitted source such as Brightmark has a fire that qualifies as an "emergency" as defined under 326 IAC 2-7-1(12) that lasts one (1) hour or more which results in a exceedance of a permit emission limit, then the source is required to notify IDEM, OAQ by telephone or facsimile within four (4) daytime business hours and submit an Emergency Occurrence Report Form within two (2) working days.

Regarding the comments about dioxin emissions, please see the IDEM Response to Comment 17.

No changes to the draft permit were made as a result of this comment.

Comment 2:

On April 26, 2022, Carolyn McCrady submitted the following comments by regular postal mail:

I am writing in regard to Fulcrum BioEnergy' s plans to build a trash to biofuel facility on Gary's lakefront. My remarks pertain to the air permit application for this facility you now have before you.

I have lived in this city since 1978 and during that time, I have breathed the air and played in the waters of Lake Michigan. But because I live in an Environmental Justice community, I am reminded daily of the harm to people who have suffered in terms of cancer and respiratory diseases. This includes members of my family and my friends.

Therefore, I am concerned about Fulcrum's plans to bring, on a daily basis, 120-128 diesel trucks into their proposed biorefinery on Gary's west side lakefront location. Those same trucks will then leave the lakefront only to return the next day, refilled with the "feedstock" they will create and house south of Gary. That is over 200 trucks a day added to the already congested highways and polluted air.

As with the proposed Maya facility on 35th Avenue between Grant and Chase Streets, I am very upset at the thought of that level of truck traffic (both tailpipe and top of the rig emissions) adding to what is already a highly polluted area. Fulcrum acts as if this additional truck traffic will be negligible and it might have been had we been located in another area like their desert location outside of Reno, Nevada.

But we live here and they want to locate in a specific area which is a highly industrialized, highly polluted and is populated both in Gary and East Chicago with some 35,000 people. Of course, because air currents travel, more than those thousands would eventually be affected by this additional pollution.

I implore your staff at IDEM to look at the cumulative effect of the increased truck traffic as well as the possibility of a spill, accident or fire in its biorefinery operation. We have heard of such a fire that occurred in May of 2021 at the BrightMark plant in Ashley, Indiana. The plume was so huge that it took several fire departments to eventually bring it under control. And so I ask, what would the outcome be here? Don't we need to know whether the Gary Fire Department has had extensive conversations about a possible event? And perhaps the East Chicago Department too. Will Fulcrum create a fire management team on-site?

Ashley is located in a rural area in a town of 930 people. I am sure that their air and soil and water quality was deeply affected by that fire because Brightmark was "gasifying" plastic which would have dispersed dioxin into the air. To my knowledge, they are still not operational.

Furthermore, the public does not know how the fire started or why. The company has been silent as has been the town of Ashley. How is this possible?

The scary thing is that Fulcrum claims their feedstock will consist of 30% plastic.

I am hoping that as you examine their air permit that you take into consideration the whole picture. As you know, Fulcrum has not produced a hazard analysis nor do they have a documentable track record of safe operation.

In light of this, it would seem reasonable for IDEM to defer the draft permit decision until the time that Fulcrum has demonstrated with documentation over a significant period of time that its Sierra plant near Reno has operated in a safe and environmentally sound manner.

And finally, in order for everyone to have a say beyond May 2 and the hearing set for April 27, I am requesting that IDEM extend the 30-day comment period.

Our city and everyone on the lakefront including Chicago must know for certain that such a tragedy will never happen here. So much harm has been done to the people and the land and the water by industry. When will our health begin to be the first priority?

IDEM Response to Comment 2:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 5 - Possible Future Violations
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 12 - Public Hearing

With respect to comments about the fire that occurred on May 14, 2021, at the Brightmark Plastics Renewal Indiana 2, LLC, plant in Ashley, Indiana, IDEM, OAQ has no information as to the cause of the fire, the types of material(s) involved in the fire, or the steps takes to put out the fire. In addition, IDEM, OAQ is not aware of any testing (air, water, or soil) that was done in the area following the fire.

If a permitted (Part 70 or FESOP) source such as Brightmark has a fire that results in a deviation(s) from any air permit requirement(s) or an exceedance of an air permit limitation(s), then that source would be required to report the deviation(s) and any response steps taken as part of a Quarterly Deviation and Compliance Monitoring Report. If a permitted source such as Brightmark has a fire that qualifies as an "emergency" as defined under 326 IAC 2-7-1(12) that lasts one (1) hour or more which results in a exceedance of a permit emission limit, then the source is required to notify IDEM, OAQ by telephone or facsimile within four (4) daytime business hours and submit an Emergency Occurrence Report Form within two (2) working days.

Regarding the comments about dioxin emissions, please see the IDEM Response to Comment 17.

No changes to the draft permit were made as a result of this comment.

Comment 3:

On April 26, 2022, Kay Rosen submitted the following comments by email:

I cannot attend the hearing tomorrow so I wanted to email you my comments instead regarding the Fulcrum Centerpoint Trash-to-Fuel Refinery, which we strongly oppose. We have lived close to Lake Michigan for 55 years and experienced decades of pollution spewing into our air and water from companies on its shore, companies who use this magnificent resource as a dumping ground. Fulcrum will add to the destruction of the quality of human and environmental life. (I am sure that my chronic lung disease has been caused/exacerbated by the air quality near my community.)

Secondly, Fulcrum has a questionable track record of safety and effectiveness judging by its lack of production at its other location in Nevada. That must be investigated and properly considered.

In this day and age when we are acutely aware of and concerned about our fragile environment and its citizens, it would be irresponsible to allow Fulcrum to build in this location. Perhaps they can find another location that is safer and will still provide economic benefit to the area.

We hope you will help keep Lake Michigan off the dumping rolls.

IDEM Response to Comment 3:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

Comment 4:

On April 27, 2022, Susan Thomas submitted the following comments by email:

I am writing on behalf of Just Transition Northwest Indiana, a grassroots environmental justice organization in the region, about the air permit for the Fulcrum BioEnergy fuel refinery. We **oppose** this unproven, risky industry being allowed to operate in Buffington Harbor on the shores of Lake Michigan in Gary, Indiana, a city already so overburdened by cumulative industry pollution that it boggles the mind.

According to the report by the Hoosier Environmental Council entitled *Assessment of Environmental Needs in Northern Lake County,* Gary has at least 52 CERCLA/Superfund sites, 423 hazardous waste sites, and more than 460 underground storage tanks. Gary has some of the worst air quality in the nation due to toxic releases from existing polluting facilities and the country's 8th highest rate of cancer. EPA also estimates Gary children are exposed to airborne toxins, metals, industrial by-products, and volatile organic compounds at a rate far higher than those outside this region.

We are staunchly opposed to greenwashed, false solutions like Fulcrum and taking gambles that would jeopardize the health of Gary residents. After years of delays, Fulcrum's plant in Reno, Nevada, has only recently become operational. We implore IDEM to heed the Cautionary Principle and reject this air permit application. We request you extend the public comment period for this permit by 30 days so the entire community can weigh in.

The environmental justice community of Gary deserves a chance to thrive and rise above being treated as a sacrifice zone, a place where people's health are sacrificed for the benefit of polluting industries or more affluent, often white, communities. IDEM must move forward to oppose this permit to safeguard Gary's health, economy, environment, and the entire Region. Please do your due diligence and deny this permit.

Thank you for your consideration.

IDEM Response to Comment 4:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 12 - Public Hearing

No changes to the draft permit were made as a result of this comment.

Comment 5:

On April 27, 2022, Molly DeVore submitted the following comments by email:

I am contacting you because I would like to receive email updates regarding permit F089-44042-00660.

IDEM Response to Comment 5:

On April 28, 2022, IDEM, OAQ emailed Molly DeVore instructions for checking the status of the Fulcrum permit on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. A copy of the draft permit and the final permit decision is also available at this internet site.

If you would like to be added to the interested parties mailing list receive notices about permit actions for this source or county, please see the instructions on the internet at: https://www.in.gov/idem/airpermit/contact/

No changes to the draft permit were made as a result of this comment.

Comment 6:

On April 28, 2022, Amanda Shepherd submitted the following comments by email:

I am writing on behalf of the Sierra Club Hoosier Chapter with concerns about the proposed permit for Fulcrum Centerpoint, LLC (FESOP # F089-44042-00660).

We have deep reservations about the proposed gasification facility that intends to turn garbage into jet fuel. Our concerns are related to the feasibility of the technology; the environmental injustice of releasing additional air pollution in an overburdened community of color; problems associated with transporting materials to the facility; and whether the facility would actually be able to operate as advertised.

Fulcrum has no track record and makes no data available for public scrutiny of the safety or validity of its claims of efficacy. The company's only other facility, the Sierra plant in Reno, Nevada, has been in the works for 8 years. However, it is still non-operational and has not produced a single gallon of fuel.

We request that IDEM extend the public comment period for the Fulcrum Centerpoint "federally enforceable state operating permit" application an additional 30 days to allow us and other community members to more completely review the 300-page draft permit.

Further, we support requests by allied groups including Gary Advocates for Responsible Development (GARD), Brown Faces Green Spaces, the Gary Branch of the NAACP, and Just Transition Northwest Indiana that IDEM deny this permit or, in the meantime, provide the environmental justice community of Gary relief by deferring this air permit and other operating permits until the Fulcrum plant in Reno, Nevada is open, functional, producing product as intended, and achieving its air permit limits.

IDEM Response to Comment 6:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 12 - Public Hearing

No changes to the draft permit were made as a result of this comment.

Comment 7:

On April 28, 2022, Gloria Moreno submitted the following comments by email:

My name is Gloria Moreno. I am a resident of Gary Indiana. I am requesting the minutes from the April 27th Gary Indiana Town Hall meeting. I also want to know the status of the air permit for Fulcrum Bio Energy.

IDEM Response to Comment 7:

On April 27, 2022, IDEM, OAQ conducted a public hearing regarding the Fulcrum Centerpoint draft New Source Construction and FESOP. Statements made by the public hearing attendees are included as Appendix C to this ATSD.

As requested, Gloria Moreno was added as an affected party to the interested parties mailing list for Fulcrum Centerpoint, LLC (Source ID 089-00660) and will be notified about any future air permitting actions for the Fulcrum Centerpoint source.

No changes to the draft permit were made as a result of this comment.

Comment 8:

On April 29, 2022, Kay Nelson submitted the following comments:

Thank you for the opportunity to comment on the issuance of the proposed Fulcrum Centerpoint LLC New Source Construction and FESOP permit No.: F089-44042-00660. The Northwest Indiana Forum (Forum) is a not-for-profit, regional economic development organization servicing over 130 members in Lake,

Porter, LaPorte, Jasper, Starke, Newton and Pulaski counties. Our focus is the retention and creation of quality employment opportunities that sustain and enhance our environment and quality of life for the residents of Northwest Indiana. Protection of the environment while enhancing the region's global competitive position is the highest priority for our members. The Forum supports the IDEM issuance of the proposed air permit to Fulcrum Centerpoint, LLC that will allow Northwest Indiana to be home to an exciting environmental and economic project.

The permit will allow the construction of a biorefinery that will accept a Processed Engineered Feedstock for gasification to create a renewable transportation fuel. Recognizing the historical carbon emission impact of our manufacturing region, the process to create the low carbon, renewable fuel will be one of many initiatives to reduce carbon emissions within our region.

The Forum supports the IDEM's decision to issue technically, scientifically and legally sound environmental permits that are crucial to our quality of life and global competitiveness. Permitting certainty, whereby state and federal regulatory agencies execute their roles and responsibilities in a fashion that when the receipt of an environmental permit allows the new and/or expansion of a facility to occur without interruption following permit issuance, is critical to the business decision making processes. Corporate long range economic development projects can only be implemented, rightfully so, with the receipt of quality environmental permits.

Recognizing that IDEM has drafted this permit in a manner to comply with current federal and state environmental laws that are protective of the environment for the residents and employees in Northwest Indiana, Fulcrum Centerpoint, LLC should receive the New Construction and FESOP final permit.

Additionally, this project will utilize an existing Industrial Zoned portion of Buffington Harbor within Gary. The Northwest Indiana Forum supports the creative reuse of underutilized properties that results in the generation of jobs and expansion of the tax base. Permit issuance will allow the construction of a new technology that has significant environmental improvement benefits, will create numerous construction jobs along with provide training opportunities for the employment positions for the biorefinery.

Again, thank you for the opportunity to offer support of the IDEM issuance of the New Source Construction and Federally Enforceable State Operating Permit (FESOP) for Fulcrum Centerpoint, LLC.

IDEM Response to Comment 8:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit

No changes to the draft permit were made as a result of this comment.

Comment 9:

On April 29, 2022, Julia Roesler submitted the following comments by email:

This is the Sierra Club Dunelands Group comment for the public hearing on permit #F089-44042-00660, the draft IDEM Federally Enforceable State Operating Permit (FESOP) Construction and Air Permit for Fulcrum Centerpoint in Gary, Indiana.

Lake Michigan is Indiana's premier resource, and we should be taking steps to clean it up and improve it to enhance Gary’s quality of life and economic viability. The proposed Fulcrum Centerpoint gasification plant is planned to be built on the shore of Lake Michigan, an area once envisioned in the Marquette Plan to be restored for Lake access and recreation to benefit the public. The location is also right next to East Chicago’s only bit of public Lake Michigan shoreline, Jeorse Park.

Converting garbage to aviation fuel sounds like a fantastic dream. It may be just that, a dream. In July of 2021, Fulcrum BioFuels announced it completed construction of the world's first commercial-scale plant converting municipal solid waste to jet fuel through gasification, the Sierra BioFuels Plant in Reno, Nevada. Their stated plan was to begin fuel production last year. Nine months later, they have still not started that anticipated production.

It's not easy to produce jet fuel from Municipal Solid Waste through gasification, and the larger the scale, the more difficult it is. That is why it has never been done successfully before on a commercial scale. Ever. The proposed project in Gary would have three times the scale of the Sierra plant. Please defer the draft permit decision until the Fulcrum Sierra Plant is operational, achieves or exceeds environmental regulatory limits, and produces jet fuel that meets industry and agency standards.

We are concerned that this technology is not proven to work without the inherent problems of gasification. Particulate matter byproducts can be toxic and cause equipment fouling and severe corrosion if not removed properly. Over time, equipment and pipes can begin to leak and increase air and water pollution. If the permit is granted, approval must mandate stringent requirements for proper oversight, maintenance, and replacement of worn-out equipment to prevent pollution and possible explosions. Air quality in the environmental justice area is a concern and permit enforcement in the case of poor equipment maintenance will be an issue. Air pollution will turn into water pollution for Lake Michigan, the primary source of drinking water for NW Indiana and the Chicago area. The Indiana State Legislature has not properly funded the Indiana Department of Environmental Management to exert proper oversight and control.

The Sierra Club Duneland Group opposes the Fulcrum Centerpoint Municipal Solid Waste Gasification Plant.

IDEM Response to Comment 9:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 4 - Fugitive Dust and Particulate Matter
- IDEM Response to General Statement 5 - Possible Future Violations
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 9 - Pollution Control, Compliance Determination/Monitoring, and Stack Testing

Regarding comments about maintenance and replacement of worn-out equipment to prevent pollution and possible explosions, the proposed air permit contains preventive maintenance requirements.

Conditions B.13 and D.1.5 of the proposed air permit require that the Fulcrum Centerpoint prepare and maintain Preventive Maintenance Plans (PMPs) for each of the emission units and control devices at the source. The PMPs shall specify the procedures and individual(s) responsible for inspecting, maintaining, and repairing emission units and control devices. Compliance with the PMP requirements will help Fulcrum Centerpoint to minimize the possibility of accidents at the plant. PMPs are typically kept on site so that on-site employees can effectively implement the PMPs and so that a copy is available for review by an IDEM, OAQ

inspector. During an inspection, the IDEM, OAQ inspector will perform a records review, which includes review of PMPs, to determine if the source is in compliance with the PMP requirements.

No changes to the draft permit were made as a result of this comment.

Comment 10:

On April 29, 2022, Simon Doughty submitted the following comments by email:

My name is Dr. Simon Doughty, and I would like to submit comments regarding the proposed Fulcrum Counterpoint LLC plant in Gary, IN, for the production of sustainable aviation fuel (SAF) from municipal solid waste (MSW).

I would like to submit that your office should proceed with issuing permits for this plant to operate, subject to the normal due diligence exercised for industrial operations by the State of Indiana.

I am a consultant in the area of renewable fuels from non-fossil sources, after a career spent in the chemical and petroleum refining industries, including emissions controls catalysts. My core experience is in catalysts, and I worked for well-known companies in the field as Johnson Matthey and Heraeus Precious Metals. I am located in Chicago, IL, just across the state line, a resident for 30 years.

Most recently, I have been consulting in the area of renewable propane, on behalf of a major Dutch company, looking at using raw materials either from plants such as soy or corn oil, or other less traditional raw materials such as MSW, to make renewable propane gas as an alternative to fossil fuel. My comments here are as a private citizen and are not on behalf of any employer or other principal.

There is already plenty of working knowledge of the conversion of MSW to raw material for either SAF or other fuel types, in particular dimethyl ether (DME). Of most relevance is the recently-formed company Dimeta for the production of DME from MSW, whose parent company is UGI, better known in this region as the Amerigaz propane. Dimeta is building a demonstration plant in England for the conversion of MSW to DME based on similar gasification technology that will be employed by Fulcrum. This gasification technology is a well-established and safe technology, and offers hope that the mountains of MSW in the world can be diverted back into useful energy products such as SAF. There are other gasification projects within the USA similar to Fulcrum.

The airlines in this country have committed to using SAF as a replacement for fossil jet fuel, with the target of getting to net-zero carbon emissions by 2050. This offers the prospect of additional energy security in the USA as well as planet-saving carbon emissions reductions. These are important and noble changes to the old ways of doing business in this country, and Indiana has the opportunity to be at the forefront of this important step-change in avoiding CO2 emissions from burning fossil fuels.

There is no perfect solution to the question of preventing global warming, no "silver bullet": at best, we will find we are using “silver buckshot”. Fulcrum offers a useful solution which, once operational, can be further scaled up around the country, such that municipalities can offer viable alternatives for the pressing problem of what to do with MSW from their communities. Similarly, IDEM in Indiana could take additional steps to protect the local Gary community by insisting that delivery trucks to the Fulcrum plant are properly and verifiably equipped with the latest tailpipe exhaust emissions control technologies for their diesel fueled trucks. Diesel particulate filters with NOx reduction systems such as SCR are highly effective, and are probably on most municipal garbage trucks in Indiana, for example.

Finally, the Fulcrum plant offers a chance for a solid jobs platform, not only for their own plant, but also at local refineries or blending facilities where the Fulcrum products can be blended into SAF. Indiana could also be at the forefront of using SAF from a future Fulcrum plant at the Indianapolis and Gary airports, rather than these products being shipped to California or elsewhere.

I trust my comments will provide useful background.

IDEM Response to Comment 10:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads

No changes to the draft permit were made as a result of this comment.

Comment 11:

On April 30, 2022, Becky Hanscom submitted the following comments by email:

I am a 33 year resident of Gary, IN and I'm requesting that you extend the 30-day comment period for Permit #F089-44042-00660. I am not able at this time to counter the proposed permit on the grounds of technical aspects that are questionable because the draft permit is SO LENGTHY. I need more time to read it and research it.

This is important to me because I have cancer – and heart failure due to the drugs used to slow down the cancer. Is the cancer environmental? No physician will say because it is 'unproven.' But I know we all need cleaner air, not air that is more contaminated by truck emissions and emissions from a trash feedstock gasification process that is unproven. Science is based on facts and physical evidence, and this process and its residual effects have not resulted in either. There is every reason to wait for evidence from the Fulcrum Sierra plant. It just makes sense that an innovative yet unproven process must be verified and tested.

I know how expensive it has been to try to clean up my cancer, and we're all paying for it. It would have been better to try to prevent it in the first place. I feel the same about the Fulcrum process. Don't hasten to permit a project when we don't really know its side-effects.

I believe you need to take serious consideration of the reservations and statements of G.A.R.D. as regards this proposed project. As a member of the community that will be affected by the Fulcrum plant, I feel G.A.R.D. has proven data-based expertise and concern for environmental justice in our community.

Time is not on my side. That's a fact. But it is also a fact that you can delay giving acquiescence to a company whose operational process is unproven and untested. We don't need to add to the pollution in our area. Grant the time to do this right. Delay, better yet deny, Permit #F089-44042-00660.

IDEM Response to Comment 11:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 12 - Public Hearing

No changes to the draft permit were made as a result of this comment.

Comment 12:

On April 30, 2022, Dorreen Carey submitted the following comments by email:

First, I would like to state that notwithstanding the preliminary findings of draft FESOP No. F089-44042-00660, this trash to fuel refinery should never have been considered for permitting and construction at the proposed Gary Buffington Harbor location, on the shoreline of Lake Michigan surrounded by the Environmental Justice communities of Gary and East Chicago, Indiana.

With regard to the draft permit:

1. I am requesting on behalf of myself and concerned community members that due to the complexity of the process and technical nature of the draft permit that the public comment period be extended for an additional 30 days.

2. The Fulcrum trash feedstock gasification process has not yet proven successful. The recently constructed Fulcrum Sierra plant in the Nevada desert originally slated to be operational in the 4th quarter of 2021 has pushed that date to the 4th quarter of 2022. I am requesting that the IDEM defer any decision on the draft permit for Fulcrum Centerpoint until the Fulcrum Sierra Plant in the Nevada desert is fully operational, achieves environmental regulatory limits, and produces jet fuel that meets ASTM standards.

3. The environmental justice status of the Gary and East Chicago communities bordering the proposed location of the Fulcrum Centerpoint facility at Buffington Harbor must be taken into account when considering permitting a new source of pollution. Historic and current operations of steel mills, refineries, and related industries have overburdened these communities with the results of air, land, and water pollution.

   I request that prior to any further consideration of the draft FESOP permit that the IDEM conduct an Environmental Justice screen and impact analysis for neighborhoods within a three-mile radius of the proposed facility. The results of this analysis should be shared with the affected communities through a publicly advertised meeting that provides the opportunity for discussion and feedback. The resulting determination of environmental justice community impact should be included in the permit decision making process.

4. How can the IDEM ensure that the municipal garbage proposed for the Fulcrum gasification process will provide a consistent feedstock when there is no documentation of where or how the municipal waste will be processed? How can the construction and operation permit be considered without the benefit of this information?

5. An estimated 200+ trash feedstock truck trips per day will travel Cline Ave to and from the proposed Fulcrum Centerpoint plant increasing diesel tailpipe emissions experienced by neighborhoods fronting Cline Ave. I request that the IDEM require Fulcrum to factor increased diesel tailpipe emissions resulting from their operations into their emissions inventory and that these emissions be included in the IDEM assessment of Environmental Justice impacts.

6. The Fulcrum Centerpoint location is adjacent to the Indiana Department of Natural Resources Clark and Pine nature preserve and remnant Dune and Swale wetlands. How will the IDEM and sister agencies ensure that these sensitive natural areas are protected if new industrial construction and operation is added to existing impacts?

7. The Grand Calumet River and Nearshore Lake Michigan are listed as a Great Lakes Area of Concern and millions have been spent as a result of the IDEM Remedial Action Plan to clean up the river and restore and preserve surrounding natural areas. Permitting construction of new industrial facilities along the shoreline does not support the goal of cleaning up and protecting Lake Michigan. How

does the IDEM ensure coordination between its programs and actions to make sure they are not at cross purposes?

8. The Marquette Plan initiated by former Congressman Peter Visclosky called for a restored and accessible Lake Michigan shoreline to include trails, greenspace and other sustainable uses on former remediated industrial properties. Constructing new industrial sources on brownfields properties where millions have been spent to clean up past pollution does not make environmental or economic sense. How does the IDEM take into account the highest and best future uses of remediated properties and their protection against recontamination?

Thank you for the opportunity to comment.

IDEM Response to Comment 12:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 12 - Public Hearing

<u>Regarding Comments about Use of Proposed Biorefinery Property</u>

With respect to the comments about the use of the proposed biorefinery property, IDEM, OAQ does not have the authority to take into account the future uses of remediated brownfield properties. These types of evaluations and/or decisions are made by other government bodies, such as the City of Gary Economic Development Commission, the City of Gary Department of Planning & Redevelopment, and/or the City of Gary Zoning Department.

No changes to the draft permit were made as a result of this comment.

Comment 13:

On May 1, 2022, Linda Murphy submitted the following comments by email:

I am writing to impress upon you that the location for the Fulcrum facility has been poorly chosen. Please do not allow any more industry on our lakefront. Lake Michigan is a resource to be protected at all costs. Even though this site had been used for industry, we should now be turning this land into a greenway. That is a much higher use, as I am sure former Representative Pete Visclosky would agree. There are other locations within Gary that are not so environmentally sensitive – choose one of those. Please do not allow Indiana to have to be embarrassed when those from other states that also use Lake Michigan decide to weigh in on protecting our environment. Indiana already ranks last as the most polluted state – you can turn that around on your watch.

IDEM Response to Comment 13:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

Comment 14:

On May 1, 2022, Adriane Blaesing submitted the following comments by email:

IDEM should not approve the Fulcrum Centerpoint, LLC Federally Enforceable State Operating Permit (FESOP) and New Source Construction 089-4404200660. The permit is not protective of human health and the environment to the degree that the Clean Air Act rules require, particularly when the facility will be in an environmental justice community recognized by the Environmental Protection Agency. Federal and state agencies have spent millions of Natural Resources Damages Assessment dollars to remediate the Grand Calumet River. Citing a facility with the permitted FESOP emissions limits will compromise the River's airshed and watershed and the Lake Michigan airshed and watershed.

FESOP Section D.1.2 (1) notes that Total VOC emissions from the Fischer-Tropsch synthesis reactor shall not exceed 48.12 tons per year for a 12 consecutive month period. FESOP Section D.1.3 notes that VOC emissions from the boiler controlling the Fischer-Tropsch reactor will operate with an overall VOC efficiency of not less than 98.0% and VOC emissions from the boiler stack shall not exceed 1.23 lb/hr. IDEM OAQ applies these limits because the agency determines that Fulcrum Centerpoint will operate as a minor source under the New Source Performance Standards (NSPS) Maximum Achievable control standards for a biorefinery.

To protect an environmental justice community and to follow Clean Air Act requirements, IDEM should not set Fulcrum's NSP standards as a biorefinery. IDEM should set limits such that the facility obtain a Title V permit for municipal solid waste incinerators. As currently written, the FESOP accepts Fulcrum's statement that they will operate only with process-engineered feedstock produced at separate off-site facilities from municipal solid waste. However, Fulcrum does not prove that their methods for producing feedstock are distinct from solid waste. Fulcrum has not yet demonstrated their feedstock production to guarantee that they are not simply using solid waste. To protect Gary's community from further environmental injustices, IDEM should require Fulcrum document a minimum one-year record that they operate their Nevada biorefinery with feedstock and not municipal solid waste.

The FESOP justifies that no Title V permit requirements for solid waste incinerators applies because US EPA issued an Applicability Determination Index for the Conversion of Post-Sorted Municipal Solid Waste Feedstock. However, the March 30, 2010 determination only applies to a facility that has not been constructed. Since that 2010 determination, Fulcrum has constructed the Nevada facility. IDEM should use the Nevada facility operations to establish that the feedstock is homogeneous and not simply municipal solid waste.

The FESOP notes that Fulcrum will require continuous emissions monitoring for NOx but not VOCs. The determination is made because the permit application uses emissions factors to calculate that the projected emissions will be less than the Title V major source threshold. Emissions factors can give variable projections and should only be used as a last resort when no real live data are available.

Fulcrum can provide real live data when the Nevada facility operates. IDEM should wait for that data availability and then determine whether the Gary facility will emit less than the Title V major source threshold.

Although IDEM has held public meetings about the FESOP, IDEM should recognize that the science, law and engineering used to approve or deny the permit is difficult for most people to comprehend. Undoubtedly, the Gary City Council welcomes Fulcrum Centerpoint because of promised jobs. Clean Air Act rules are difficult for lay people to understand. I suspect that if the citizens living in the affected environmental justice community understood that the facility could be permitted to follow rigorous Title V requirements with more stringent emissions limits and continuous emissions monitoring, then they might withstand citing another refinery in their backyard. The FESOP as proposed presently hoodwinks the environmental justice community. Until Fulcrum provides one year of operational data from the Nevada facility, then can the Gary City Council and affected residents know that the biorefinery may not negatively impact human health and the environment.

IDEM Response to Comment 14:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 11 - Incineration

While the Nevada facility is not yet fully operational, engineering data provided by Fulcrum indicates that Fulcrum will be able to comply with the requirements of the proposed permit. Therefore, IDEM OAQ has no justification for requiring a delay in the issuance of this proposed permit.

The proposed permit contains all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board (ERB), which will limit the amount of emissions from the facility to the very lowest level allowed by law. IDEM, OAQ has no authority to create any permit limits or measures that exceed what is legally required for a regulated source.

No changes to the draft permit were made as a result of this comment.

Comment 15:

On May 2, 2022, Mary Ann Summer submitted the following comments by email:

I ferociously oppose the Fulcrum facility and request an environmental justice screening and analysis for the area. Until the Reno operation has been proven to be a success, this Gary operation should be put on hold - it will bring more pollution and toxicity to our overburdened area.

IDEM Response to Comment 15:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit

- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

Comment 16:

On May 2, 2022, Pete Julovich submitted the following comments by email:

I was not able to voice my comments at the April 27th public hearing and wish to submit written comment(s) below:

(1) The Nevada plant is located in the desert area where the public is not exposed to health-related emissions and physical hazards.

(2) Please call Nevada EPA Region, state, local, and county regulators and get a copy of all their permits (solid waste permits, water permits, air permits, and fire marshal permits) before you approve for issuance.

(3) Please consult US EPA emission technology clearing house for legally required control devices.

I think IDEM needs to pause issuance and re-evaluate the LAER (O_3) and BACT (PM) technical issues related to control technologies for this refinery handling explosive/highly flammable liquids.

IDEM Response to Comment 16:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit

Below are IDEM's responses to each of the comments:

1. This proposed permit is protective of human health and the environment and will allow for environmentally sound operations that may support a prosperous economy. The proposed permit contains all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board (ERB), which will limit the amount of emissions from the facility to the very lowest level allowed by law.

2. IDEM, OAQ reviewed all information provided by Fulcrum Centerpoint in its permit application, requested additional information and/or clarification when necessary, and determined that the information was sufficiently adequate for determining the potential to emit (PTE) of the proposed facility and the applicability of state and federal air rules and air regulations.

   The proposed permit renewal contains all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board, which will limit the amount of emissions from the facility to the very lowest level allowed by law. The permit also contains all applicable control device operating requirements, monitoring requirements, testing requirements, and associated record keeping and reporting requirements to assure

that all permit limitations are enforceable as a practical matter and to assure that the source can demonstrate compliance with all applicable state and federal rules on a continuous basis.

As part of the permit application review process, IDEM OAQ obtained a copy of the most recent air permit for the Fulcrum Sierra Biofuels LLC biorefinery (Facility ID A0921) near Reno, Nevada. The permit was downloaded from the Nevada Division of Environmental Protection Public Document Search website at https://ecms.nv.gov/ndep/.

The most recent air permit was Permit Administrative Amendment AP1629-3964.01 (dated February 23, 2022), which can be accessed at the following internet hyperlink https://ecms.nv.gov/ndep/api/Document/ASPKX%C3%81fmWyDymFGFwd0keISN1My%C3%81NVi8Is3KC3%C3%81dbAPzZRI%C3%894bTRyIumYTeJc2dbwcnQ6YfIOf%C3%81MdI1QKQUwZkQ%3D/.

IDEM, OAQ has determined that obtaining copies of solid waste permits, water permits, and fire marshal permits from Nevada EPA Region, state, local, and county regulators is not warranted as IDEM, OAQ has no authority over these issues.

3. The commenter requested IDEM, OAQ to "consult US EPA emission technology clearing house for legally required control devices" which is US EPA's RACT/BACT/LAER Clearinghouse (RBLC) (https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information). As discussed in this comment response below under items 4 and 5, this source The proposed new source is not a major source under Emission Offset (326 IAC 2-3) and not subject to the requirements of Emission Offset (326 IAC 2-3) or Lowest Achievable Emission Rate (LAER) and this new source is not a major source under Prevention of Significant Deterioration (PSD) (326 IAC 2-2) and not subject to the requirements of PSD (326 IAC 2-2) or PSD-BACT. However, as specified in permit Condition D.1.3 and discussed in the Technical Support Document (TSD), the one (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, is subject to the requirements of the state rule 326 IAC 8-1-6 (VOC BACT) and is required to control VOC emissions using Best Available Control Technology (BACT). As part of the BACT analysis that was performed for the Fischer Tropsch (FT) Synthesis reactor, the RBLC database was reviewed to identify control requirements and limitations for facilities similar to the proposed biorefinery (see Appendix B to the TSD).

4. With respect to Emission Offset (326 IAC 2-3) and Lowest Achievable Emission Rate (LAER), IDEM, OAQ does not have legal authority to create any permit requirements that exceed what is legally required for a regulated source. As explained in the Technical Support Document (TSD), Lake County is currently designated as serious nonattainment for the 2008 8-hour ozone standard and volatile organic compounds (VOC) and nitrogen oxides (NOx) (both precursors to ozone) are evaluated to determine the applicability of Emission Offset (326 IAC 2-3). The Emission Offset major source threshold level for VOC and NOx is 50 tons per twelve (12) consecutive month period, each. The proposed new source is not a major source under Emission Offset (326 IAC 2-3), because the NOx and VOC emissions from the entire source are each limited to less than the Emission Offset major source threshold level of 50 tons per twelve (12) consecutive month period. Therefore, the requirements of Emission Offset (326 IAC 2-3) and Lowest Achievable Emission Rate (LAER) are not applicable. VOC and NOx emission limits are included in permit Conditions C.1 and D.1.2.

5. With respect to Prevention of Significant Deterioration (PSD) (326 IAC 2-2) and PSD Best Available Control Technology (PSD-BACT), IDEM, OAQ does not have legal authority to create any permit requirements that exceed what is legally required for a regulated source. As explained in the TSD, Lake County is designated as attainment for PM10 and PM2.5 and direct PM2.5 emissions and sulfur dioxide (SO2) and NOx emissions (both precursors to PM2.5) were reviewed pursuant to the requirements for PSD, 326 IAC 2-2. The PSD major

source threshold level for PM, PM10, PM2.5, SO2, and NOx, is 250 tons per twelve (12) consecutive month period, each. The proposed new source is not a major source under PSD (326 IAC 2-2), because the PM, PM10, PM2.5, SO2, and NOx emissions from the entire source are each less than or limited to less than the PSD major source threshold level of 250 tons per twelve (12) consecutive month period. Therefore, the requirements of PSD (326 IAC 2-2) and PSD-BACT are not applicable. PM, PM10, PM2.5, and NOx emission limits are included in permit Conditions C.1, D.1.1, and D.1.2.

No changes to the draft permit were made as a result of this comment.

Comment 17:

On April 27, 2022, George E. Smolka submitted the following comments by hand delivery at the public hearing (these comments were also submitted by email on May 2, 2022):

(1) What is the highest temperature that this process achieves and for how long?

(2) How do you achieve this operating temperature?

(3) Since Fischer-Tropsch is a gas phase reaction how does this process gasify the solid and semisolid components such as paper, asphalt, wood, paint, vegetable detritus, and other organic materials?

(4) How does this process prevent salt (sodium chloride) or other chlorinated garbage from entering with the feed stock?

(5) What is the concentration, in picograms, of TCDD (dioxin) in the process effluent gases?

(6) How does SASOL technology compare to this process, and where did Fulcrum get this technology?

(7) The DOD is not an experts in chemical technology. BP, if you mean British Petroleum, is but Fulcrum does not give the results of those reviews. They could be negative.

(8) Do any of you know Arrow Ecology? Why have they not been invited here to give a counter proposal to Gary?

On May 2, 2022, George E. Smolka submitted the following comments by email:

I have updated and expanded my original submission of a series of questions. I would appreciate a speedy reply.

I would also like to know why Fulcrum is not required to answer in person, serious concerns about the effectiveness and reliability of their technology considering the toxic potential of their proposed technology. Are they afraid to face knowledgeable questioners because their inflated claims are a scam? Or are they incompetent to answer for the lack of progress in Nevada?

I have substantive issues with the use of any portion of the MSW as fuel for this process and will take other action if IDEM does not answer these concerns fully and with alacrity.

Email Attachment:

At the Gary, Indiana open meeting held on 27 April 2022, I submitted a set of questions concerning the process proposed by Fulcrum for the conversion of Municipal Solid Waste to jet fuel. My verbal commentary involved some technical points about the serious defects with the proposed technology,

deceitful and erroneous statements on Fulcrum's website, and a limited comparison with a known economically viable Fischer-Tropsch process from the company SASOL, of South Africa.

I will now elaborate on this submission:

(1) The reason for my inquiry about the maximum temperature of the process is that from the material on Fulcrum's website concerning the process, no data is given as to the operating temperature of their process. Fischer-Tropsch reactions usually are carried out at 150-3000°C. No indication is made as to how such a temperature will be reached. Importantly, what fuel will be used, under what conditions and how the temperature will be maintained. If a portion of the delivered MSW is also to be used as the fuel, then the process is also a garbage incinerator, requiring separate permitting, restrictions, and monitoring, and may not be allowed at a site so close to our main drinking water source, Lake Michigan.

This obviously also includes Question 2, since the achievement and maintenance of temperature are part of a functional process.

Please answer all my question points in detail. I will not accept an incomplete or perfunctory answer.

(3) The gasification is an integral part of the Fischer-Tropsch process. While the reformation step and catalysis is open to trade secrecy, gasification has been described since 1928, is covered by patents that have lapsed long ago, and cannot be covered by any statement of trade secret. I will view any attempt by Fulcrum to withhold such information as obfuscation; and will make public such an attempt.

I want a detailed description of the separation, micronization, and fluidization steps involved. Also, the full description of rate and curve of the temperature increase, and any plateau.

(4) The question concerns the fact that any municipal waste is contaminated with varying levels of ordinary salt (sodium chloride) and other chlorinated materials, both organic and inorganic. The presence of such material allows the formation of dioxins (TCDD etc..) at the normal operating temperature of a Fischer-Tropsch system. While the optimum temperature for such formations is 400-7000°C it can form in local hot spots and under other conditions. Northwest Indiana is already contaminated with an excessive amount of such and similar materials. These materials pose an alarmingly high risk for all the people in all of Northwest Indiana and beyond.

Since the USEPA's level of toxic effects for TCDD is less than 3 picograms/day/person, I will demand to see the air effluent analysis for Fulcrum's Nevada operation over the last two years from Nevada's Environmental Management Department (or equivalent department with the same responsibility).

If you refuse to comply with my demand, I will consider it official misconduct and dereliction of duty to the people of Indiana.

My Question 5 is related to the above question in that it requires data from ongoing air effluent analysis to be submitted to IDEM by Fulcrum.

(6) This question relates to the expected economic viability of their technology. Not one piece of data for current operations in Nevada has been submitted. No data on amount of garbage processed, amount of product of any type, jet fuel or other, produced; No samples of material produced or anything else. The supporting statements submitted by Fulcrum or others are a collection of dreams and wishful thinking. All the supposed benefits are projections from no data and no discernible facts.

Therefore, I submit for comparison the proven record of achievement of the SASOL corporation mentioned above, which has been profitably operated since 1953 and is still in business using a type of Fisch-Tropsch process.

I wish to know where Fulcrum obtained their technology. What, if any, are their patents? Are they leasing it? If so, from whom?

(7) Fulcrum's website indicates that that their process was reviewed by BP, United Airlines, DOD, and engineers, Leidos and Black & Veatch. DOD and United Airlines are not FT experts. If BP is British Petroleum, then they know FT Tech. The engineering firms mentioned are very large but what is their experience in FT? Fulcrum does not excerpt any of the reviews on their website.

IDEM Response to Comment 17:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 11 - Incineration
- IDEM Response to General Statement 12 - Public Hearing

During 2021 and 2022, Fulcrum encouraged open conversation and dialogue with the public and community groups. Fulcrum conducted an extensive community outreach program in partnership with the City of Gary and has committed to continued community outreach sessions throughout 2022. For additional information, please see IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns.

<u>Regarding the Biorefinery Process Temperature, SASOL Technology, Process Review?</u>

Below is IDEM's response to the comments in items 1, 2, 3, 6, and 7:

In its air permit application, Fulcrum Centerpoint provided information regarding the proposed biorefinery plant (description of process, emission factors and emission calculation methodology used to determine the potential to emit (PTE) of the proposed facility, state and federal rule applicability, and all additional information provided as part of the permit application) and certified (signed by the responsible official) that the information was truthful, accurate, and complete. IDEM, OAQ reviewed all information provided by Fulcrum Centerpoint in its permit application, requested additional information and/or clarification when necessary, and determined that the information was sufficiently adequate for determining the potential to emit (PTE) of the proposed facility and the applicability of state and federal air rules and air regulations.

With respect to the temperatures of the gasification and Fischer-Tropsch (FT) processes, this information was not necessary for IDEM to formulate emissions limitations for the air permit. As explained in the air permit application, the heat for the gasification process will use a steam reformer that is indirectly heated using natural gas and a small quantity of oxygen will be injected into the reformer to provide any required heat above the output of the indirect heaters. The FT reactions are exothermic, and steam is generated in the FT Reactor to maintain the FT Reactor temperature. Again, it is not necessary for IDEM to know the process temperatures and how they are achieved and maintained in order to develop the appropriate emission limitations for the air permit.

IDEM, OAQ has no authority to require Fulcrum to submit additional information that exceeds what is legally required for a permit application.

As discussed in IDEM Response to General Statement 6 (under No Proven Track Record), the proposed biorefinery process (two-step process using steam-reforming gasification and Fischer-Tropsch process) to convert Feedstock into renewable transportation fuel has been proven to work at two (2) gasification facilities operating in North America.

The proposed biorefinery will “break down” and convert the Feedstock materials into diesel or jet fuel using a two-step thermochemical process of steam-reforming gasification in an oxygen-deficient atmosphere (producing syngas) and Fischer-Tropsch (FT) synthesis (producing "syncrude" FT liquids that are further upgraded and refined to diesel or jet fuel). The gasification process will not burn, combust, or incinerate the Feedstock materials (i.e., no direct flame will be applied to the Feedstock materials in the gasifier, nor will a flame be propagated as a result of the heating). The proposed gasification and the downstream processes will be fully contained. Prior to conversion to diesel or jet fuel, the syngas will go through a multistep clean-up process to remove contaminants such as sulfur, chlorine, and metals, which will be contained, captured, handled, and treated for disposal.

Regarding Feedstock Materials, the Proposed Biorefinery Gasification Process, and Dioxin Emissions

Below is IDEM's response to the comments in items 4 and 5:

For the proposed biorefinery, Fulcrum Centerpoint will use a Feedstock material derived from municipal solid waste (MSW) that will be produced at separately permitted Feedstock Processing Facilities (FPFs). The FPFs will use commercially proven processing equipment to shred and sort MSW with sequential steps recovering valuable recyclable materials, removing unwanted components of the waste stream, and improving the physical and compositional attributes of the Feedstock. The Feedstock will consist primarily of mixed paper and cardboard, soft plastic, wood, and textiles, with small amounts of food/yard waste (organic material), non-ferrous metals (e.g., aluminum), ferrous metals, inerts, and fines. During the proposed gasification process, the syngas will go through a multistep clean-up process to remove contaminants such as sulfur, chlorine, and metals, which will be contained, captured, handled, and treated for disposal.

The Feedstock material to be used in the proposed biorefinery will not be raw (unprocessed) garbage and the Feedstock salt content is expected to be low to minimal.

The proposed gasification process is not expected to emit dioxin emissions, since the conditions within the gasifier will not be conducive to dioxin formation. The oxygen-deficient atmosphere (which also prevents combustion of the feedstock material) and higher temperature in the gasifier will not provide the conditions needed for dioxin formation.

Regarding Arrow Ecology

Below is IDEM's response to the comments in item 8:

All members of the public were invited to attend the public hearing that was held on April 27, 2022. For additional information, see IDEM Response to General Statement 12 - Public Hearing. IDEM, OAQ does not specifically invite parties to a public meeting.

No changes to the draft permit were made as a result of this comment.

Comment 18:

On May 2, 2022, Robin Rich submitted the following comments by email:

Northwest Indiana's greatest asset is Lake Michigan. That's why our longtime Congressman Visclosky created the Marquette Plan to restore industrial sites, clean up pollution and make trails and other uses to benefit the public. Bringing the Fulcrum business to our precious lakeshore - as well as the nearby Wetlands - where millions have been spent to clean it up - makes no sense. It is the opposite of the direction we need to go in order to ensure a future for our kids and grandkids.

Environmental Management must include examining the Environmental Justice impact. Please conduct an analysis for the nearby neighborhoods which are already affected by the steel mills and BP Amoco. You can't just act like it's ok to pile on more trash and unproven industrial processes to this area where people are raising families. At the very least you should defer the draft permit decision until Fulcrum's other site is operational to see if they can keep within environmental limits. This process is entirely unproven!

Please listen to the voices of people in our community and take a long hard look at the potential danger to our Lake and neighborhoods.

IDEM Response to Comment 18:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

Comment 19:

On May 3, 2022, and May 16, 2022, Dorreen Carey submitted the following comments by email:

Request that the IDEM contact Nevada Department of Environmental Protection and the Fire Marshal of Storey Country to review the compliance record of Fulcrum Sierra Feedstock Processing Facility and the Fulcrum Sierra Biorefinery.

Request that the IDEM consult the USEPA Emission Technology Clearing House for legally required control devices applicable to Fulcrum Centerpoint.

Fulcrum Centerpoint process and storage tanks do not appear to have control devices. All tanks in a nonattainment ozone area located in Gary must have lowest-achievable emission rate control technologies (LEAR) control technologies to control volatile organic. Venting to atmosphere does not qualify. LEAR for tanks emissions located in a nonattainment area shall be controlled with closed tank tops including chillers to condense the vapors to liquids and recycle. Thus, the LAER CT are chillers with fixed roofs.

To ensure compliance with the reported Reid vapor pressure, daily monitoring data must be continuously recorded and made MONTHLY with a DAILY rolling average.

All particulate vents must meet best available control technologies (BACT) on roof fugitive vents, when PM is a new source.

IDEM should pause issuance of this permit and re-evaluate the LEAR (O_3) and BACT (PM) technical issues related to control technologies for this refinery handling explosives/highly flammable liquids.

IDEM Response to Comment 19:

Below are IDEM's responses to each of the comments:

1. IDEM, OAQ has determined that contacting the Nevada Department of Environmental Protection and the Fire Marshall of Storey County, Nevada, to review the compliance record of Fulcrum Sierra BioFuels Plant near Reno, Nevada is not warranted. Fulcrum Centerpoint is required to comply all air permit requirements and applicable state and federal air quality rules and regulations. If it is determined that Fulcrum Centerpoint has violated a permit term or condition, IDEM, OAQ will take appropriate action to bring to source back into compliance with applicable permit conditions, state rules, and federal regulations.

2. The commenter requested IDEM, OAQ to "consult US EPA Emission Technology Clearing House for legally required control devices" which is US EPA's RACT/BACT/LAER Clearinghouse (RBLC) (https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information). As discussed in this comment response below under items 4 and 5, this source The proposed new source is not a major source under Emission Offset (326 IAC 2-3) and not subject to the requirements of Emission Offset (326 IAC 2-3) or Lowest Achievable Emission Rate (LAER) and this new source is not a major source under Prevention of Significant Deterioration (PSD) (326 IAC 2-2) and not subject to the requirements of PSD (326 IAC 2-2) or PSD-BACT. However, as specified in permit Condition D.1.3 and discussed in the Technical Support Document (TSD), the one (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, is subject to the requirements of the state rule 326 IAC 8-1-6 (VOC BACT) and is required to control VOC emissions using Best Available Control Technology (BACT). As part of the BACT analysis that was performed for the Fischer Tropsch (FT) Synthesis reactor, the RBLC database was reviewed to identify control requirements and limitations for facilities similar to the proposed biorefinery (see Appendix B to the TSD).

3. With respect to Emission Offset (326 IAC 2-3) and Lowest Achievable Emission Rate (LAER), IDEM, OAQ does not have legal authority to create any permit requirements (e.g., requiring that all tanks be controlled with a closed/fixed roofs and vapor condensers) that exceed what is legally required for a regulated source. As explained in the Technical Support Document (TSD), Lake County is currently designated as serious nonattainment for the 2008 8-hour ozone standard and volatile organic compounds (VOC) and nitrogen oxides (NOx) (both precursors to ozone) are evaluated to determine the applicability of Emission Offset (326 IAC 2-3). The Emission Offset major source threshold level for VOC and NOx is 50 tons per twelve (12) consecutive month period, each. The proposed new source is not a major source under Emission Offset (326 IAC 2-3), because the NOx and VOC emissions from the entire source are each limited to less than the Emission Offset major source threshold level of 50 tons per twelve (12) consecutive month period. Therefore, the requirements of Emission Offset (326 IAC 2-3) and Lowest Achievable Emission Rate (LAER) are not applicable. VOC and NOx emission limits are included in permit Conditions C.1 and D.1.2.

4. With respect to reported Reid vapor pressure of the Synthetic Paraffinic Kerosene (SPK) that will be stored in the three (3) product storage tanks (T1, T2, and T3) and the one (1) off-spec product storage tank (T4), IDEM, OAQ does not have legal authority to create any permit requirements (e.g., requiring daily monitoring of the Reid vapor pressure) that exceed what is

legally required for a regulated source. The three (3) product storage tanks (T1, T2, and T3) and the one (1) off-spec product storage tank (T4) are subject to the requirements of 326 IAC 8-9-6(a), (c), and (h) which are included in Condition D.1.24 of the proposed permit.

5. With respect to Prevention of Significant Deterioration (PSD) (326 IAC 2-2) and PSD Best Available Control Technology (PSD-BACT), IDEM, OAQ does not have legal authority to create any permit requirements that exceed what is legally required for a regulated source. As explained in the TSD, Lake County is designated as attainment for PM10 and PM2.5 and direct PM2.5 emissions and sulfur dioxide (SO2) and NOx emissions (both precursors to PM2.5) were reviewed pursuant to the requirements for PSD, 326 IAC 2-2. The PSD major source threshold level for PM, PM10, PM2.5, SO2, and NOx, is 250 tons per twelve (12) consecutive month period, each. The proposed new source is not a major source under PSD (326 IAC 2-2), because the PM, PM10, PM2.5, SO2, and NOx emissions from the entire source are each less than or limited to less than the PSD major source threshold level of 250 tons per twelve (12) consecutive month period. Therefore, the requirements of PSD (326 IAC 2-2) and PSD-BACT are not applicable. PM, PM10, PM2.5, and NOx emission limits are included in permit Conditions C.1, D.1.1, and D.1.2.

No changes to the draft permit were made as a result of this comment.

Comment 20:

On May 6, 2022, Marie Siroky submitted the following comments by email:

I am hoping you can guide me where to find more information regarding the water treatment systems in Fulcrum's draft.

Specifically, are the "tanks" described inground? If you could point me to these definitions or IC it would be helpful.

IDEM Response to Comment 20:

Fulcrum did not specify in the air permit application whether any of the tanks associated the proposed wastewater treatment system would be below ground (inground) or above ground. This type of information is not required for an air permit application.

No changes to the draft permit were made as a result of this comment.

Comment 21:

On May 16, 2022, Marie Siroky submitted the following comments:

Here are my concerns with the permit. These are the 29 items IDEM has requested from Fulcrum over 90 days ago which have not been provided. The virtual file cabinet has yet to receive any of the items below. Particularly concerning is the property at 6200 Industrial BLVD requires remediation/cleanup of hazardous materials per EPA. The city and regional development applied for a grant over a year ago for cleanup, however this has not been done.

There is no assessment from the ACOE and others on the designated wetlands.

According to public records of minutes, the property has not been leased.

The GSD, which would be responsible for treatment, has ongoing EPA violations and no approval for the permit.

1) Please provide the legal description and the map of the legal description of the facility boundaries certified by a registered land surveyor
2) The facility boundary must include the traffic pattern associated with solid waste. Please clarify type of waste received and PEF is derived from municipal solid waste (MSW)
3) Clarify amount of waste feedstock to be stored. Permit lists 6,600 and also 9,600.
4) Post closure duties not identified .
5) In addition to this purchase agreement, please also provide documentation that includes a copy of a lease agreement between Riley Land Management, LLC and Fulcrum Centerpoint, LLC to establish the right to tenancy.
6) Please provide a certified copy of the deed showing ownership in the person identified as the owner in the application and evidence that ownership will be transferred to the owner. Please note the purchase states the Grantee may purchase all, or any portion, of the real estate at 6200 Industrial Highway, Gary, Indiana 46406. IDEM maintains the permit approval consists of the facility boundary and the solid waste boundary as required in the map of the legal description.
7) Depiction of Property is illegible.
8) The zoning letter states 329 IAC 11.5 is a relevant code pertaining to the proposed biorefinery. The correct code citation is 329 IAC 11, Solid Waste Processing Facilities. Additionally, the letter must specifically state the proposed biorefinery is a solid waste processing facility and the facility owner is Fulcrum Centerpoint, LLC. Please also clarify the relevance of 675 IAC 12-12-2, Underground Storage Tank Certification Program.
9) Please provide a copy of the local zoning requirements for a solid waste processing facility and a copy of the local zoning ordinance.
10) The application indicates the status of any appeals of any zoning determination is “N/A”. Please clarify if no appeals are pending. Additionally, please provide the date by which such appeals must be initiated if none pending. Also, please provide a certificate of existence from the Indiana Secretary of State’s Office for Riley Land Management, LLC.
11) All design drawings must be certified by a professional engineer. It is noted Thomas C. Yonge, P.E. has prepared the application, but it is not certified.
12) Please provide a USGS topographical map including all areas within two miles of the facility with the proposed processing facility boundaries clearly delineated.

Item III. Plot Plans.

13) Please identify any access control measures (including fences, gates, or natural barriers). Please include access control measures in the plot plans. Also include the weigh scale.
14) Please provide the plans water drainage, and storm water retention pond. Please identify the surface water drainage system in the plot plans including culverts, drainage tiles, and legal drains.
15) Please identify roads and buildings within half (½) mile of the facility on the plot plan(s).
16) All building and structures used for loading and unloading, storage, and processing of solid waste must show type of construction and construction materials on the drawings. Verify that all equipment used for processing of waste is identified in the drawing(s).
17) Please provide layout and dimensions for storage areas (indoors and outdoors) on the drawings, which is missing
18) Please identify sanitary facilities with plumbing and sewer connections on the drawing
19) Please provide a waste flow diagram for all waste streams and residues with flow rates. Application does not show the waste streams for tramp waste and bed media waste. Please revise as necessary and include tramp waste and bed media waste.
20) Permit identifies hazardous and non-hazardous wastes will be disposed in Newton County Landfill (Republic) and Liberty Landfill (Waste Management). These are not hazardous waste landfills. Please specify a hazardous waste facility for hazardous waste disposal Please note Fulcrum may need a hazardous waste generator notification and EPA ID number for this location.
21) Please specify operating records must be maintained onsite for 3 years
22) Please include “powders”, “treated or untreated infectious waste”, “radioactive materials”, “hazardous waste including VSQGs, TSCA and mercury containing materials” as prohibited materials on the appropriate pages.
23) Please provide hard copy large scale drawings.

24) Please identify the cyclone separators, dust-controlled silos and dust collection units on the drawings. Please clarify if these units are considered baghouses.
25) The US Fish and Wildlife Service identifies wetlands on the footprint of Plant B. Please complete a wetland delineation that has been reviewed by the U.S. Army Corps of Engineers
26) Industrial wastes are generated include the transportation and disposal costs; also speculative accumulation of jet fuel generated that is not sent.
27) The facility contact information (of the emergency response plan must include names and phone numbers.
28) Please include a closure certification form
29) Provide an approval letter from the City of Gary for discharge via Gary Sanitary District.

IDEM Response to Comment 21:

In its air permit application, Fulcrum Centerpoint provided information regarding the proposed biorefinery plant (description of process, emission factors and emission calculation methodology used to determine the potential to emit (PTE) of the proposed facility, state and federal rule applicability, and all additional information provided as part of the permit application) and certified (signed by the responsible official) that the information was truthful, accurate, and complete. IDEM, OAQ reviewed all information provided by Fulcrum Centerpoint in its permit application, requested additional information and/or clarification when necessary, and determined that the information was sufficiently adequate for determining the potential to emit (PTE) of the proposed facility and the applicability of state and federal air rules and air regulations.

IDEM, OAQ has no authority to require Fulcrum to submit additional information that exceeds what is legally required for an air permit application.

Below are IDEM's responses to each of the comments:

a. With respect to the comment about a brownfield cleanup grant that the City of Gary applied for to the U.S. EPA for the assessment and cleanup of property for this proposed biorefinery (6200 Industrial Highway Gary, Indiana 46406), IDEM, OAQ does not have the authority address this issue. For additional information regarding this issue, please contact the City of Gary Department of Planning & Redevelopment.

b. With respect to the comment stating that there is no assessment from the U.S. Army Corps of Engineers (ACOE) and others on the designated wetlands, IDEM, OAQ does not have the authority address this issue. For additional information regarding this issue, please contact IDEM Office of Water Quality (OWQ) or the U.S. ACOE.

c. With respect to the comment stating that the property has not been leased, IDEM, OAQ does not have the authority address this issue. This type of information may be required to be submitted to IDEM Office of Land Quality (OLQ) as part of a solid waste processing permit application, but is not required for an air permit application. IDEM, OAQ has no authority to require Fulcrum to submit additional information that exceeds what is legally required for an air permit application.

d. The 29 items included in this comment referred to information that may be required to be submitted to IDEM Office of Land Quality (OLQ) as part of a solid waste processing permit application, but are not required for an air permit application. IDEM, OAQ has no authority to require Fulcrum to submit additional information that exceeds what is legally required for an air permit application.

No changes to the draft permit were made as a result of this comment.

Comment 22:

On May 16, Dorreen Carey submitted the following comments:

The EPA Region 5 comment letter provided to the IDEM on the Fulcrum Centerpoint draft Permit # F089-44042-00660 signed by John Mooney, Director, EPA Air and Radiation Division, addresses the issue of determining whether a NHSM is a solid waste or not. The EPA comment discusses the issue below and request that IDEM include as part of the permit record a copy of the facility's NHSM non-waste determination documentation or other basis upon which the non-waste determination is being made.:

> "b. IDEM states the feedstock that is converted to syngas in the gasifier is not considered municipal solid waste since it qualifies as a Non-Hazardous Secondary Material (NHSM) under 40 CFR 241, Subpart B. We request that IDEM provide additional information in the permit record to support this conclusion, and/or revise the permit, in consideration of the following:
>
> > 40 CFR 241.3 sets forth specific criteria for a municipal solid waste to be appropriately considered a non-waste fuel. Specifically, municipal solid waste can be considered a non-waste fuel only if it has been (1) adequately processed, and (2) meets the legitimacy criteria in 40 CFR 241.3(d)(1). [40 CFR 241.3(b)(4]
> >
> > Determining whether a NHSM is a solid waste or not when it is combusted is key to understanding which CAA requirements apply to the unit that combusts the NHSM. Units combusting an NHSM that is a solid waste are subject to the requirements of CAA section 129 (e.g., NSPS Subparts AAAA and Eb), while units that combust an NHSM that is not a solid waste are subject to regulations promulgated under CAA section 112. CAA section 129 applies to solid waste combustion units such as commercial and industrial solid waste incinerators, while CAA section 112 applies to other types of units, such as boilers. If a combustion unit subject to CAA section 112 burns an NHSM that is a solid waste under the Resource Conservation and Recovery Act, then that unit will be in violation of its CAA permit. Therefore, it is critically important that non-waste determinations be done correctly. NHSMs other than traditional fuel, clean cellulosic biomass, or categorical non-waste require a determination that the NHSM is not a solid waste when burned as a fuel and meets the legitimacy criteria in the regulations. The recommended method for making a non-waste determination is the site-specific "self-determination" done by the facility that generates or combusts the NHSM, since the NHSM regulations are self-implementing. See EPA guide "Non-Hazardous Secondary Material (NHSM) Regulations 40 CFR Part 241. Guide for Waste/Non-Waste Determinations" for additional information. https://www.epa.gov/sites/default/files/2021-05/documents/nhsm_guide_5_26_2021.pdf
> >
> > Furthermore, the preamble discussion in the 2011 final rule "Identification of Non-Hazardous Secondary Materials That Are Solid Waste" includes a discussion about syngas as an NHSM (see 76 FR 15538, March 21, 2011). It states that "Synthesis gas (or syngas as it is commonly referred) produced from the gasification of solid waste is another material that can also meet the requirements of a fuel product produced from the processing of discarded non-hazardous secondary materials, *provided the syngas has been adequately processed to remove contaminants*." (*emphasis added*).
> >
> > To support a clear permit record, we request that IDEM include as part of the permit record a copy of the facility's NHSM non-waste determination documentation or other basis upon which the non-waste determination is being made.
>
> The above comments regarding the applicability of NSPS Subpart AAAA and NSPS Subpart Eb are contingent on the combusted materials being sufficiently documented to meet the

requirements of 40 CFR 241.3(b)(4) and/or the other requested clarifications/permit revisions above. "

My comment is that the Fulcrum Centerpoint NHSM non-waste determination documentation to be requested by the IDEM must be made based on the product produced by the proposed MSW processing facility for Fulcrum Centerpoint proposed to be constructed in Indiana or Illinois utilizing the MSW proposed to be collected from Indiana or Illinois, not on the product of the processing facility currently operating in conjunction with the Fulcrum Sierra refinery in Nevada. There is no way to determine if the processing facility to be built in Indiana or Illinois or the garbage that will be processed that will be collected from Indiana or Illinois will produce the same product as the Fulcrum Sierra plant. Therefore the NHSM non-waste determination must be conducted after the Illinois or Indiana MSW processing facilities are constructed, operating, and processing Illinois or Indiana MSW. This would require that the draft air permit not be approved until the Illinois or Indiana processing facilities have been constructed and are operating.

IDEM Response to Comment 22:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 11 - Incineration

Fulcrum has indicated that it has conducted several municipal solid waste (MSW) characterizations in the Greater Chicago area. The most recent characterization was completed in April 2021, which confirmed that the MSW from the Greater Chicago area was very similar in composition and physical attributes to the MSW from Reno, Nevada, and produces a similar Feedstock material after processing in a Feedstock Processing Facility (FPF).

IDEM, OAQ does not have the authority to place a hold on the air permit application (or deny the air permit application) and require Fulcrum to construct and operate the proposed Illinois and Indiana Feedstock Processing Facilities (FPFs) prior to obtaining a permit for the proposed biorefinery.

No changes to the draft permit were made as a result of this comment.

Comment 23:

On May 16, Jim Sweeney submitted the following comments by regular postal mail:

Sir, I have included a letter to the editor copied out of The Times of Northwest Indiana the other day. I agree whole-heartedly with every point made by Ms. Kaatz Chary. Please enter my letter (and hers) into the public record for this application.

Attachment:

Letters To The Editor: May 1st, 2022, The Times of Northwest Indiana

Dear editor,

What Kay Nelson's blizzard of statistics praising the proposed Fulcrum Centerpoint project (Gary's Green Economy is Poised for Significant Growth, April 24, 2022) in Gary fails to mention is the added pollution and environmental burden it will bring to the historically unequal and unfair environmental impacts the people of Gary have already experienced.

Everyone supporting this project ignores the fact that the 1,000 jobs — which no one disputes are important (if they even go to Gary residents and whose wages are unlikely to be spent in Gary) — will be temporary. They will be gone when the plant is built but the pollution will remain, making Gary's air even more unhealthy than it already is.

To date, Fulcrum, for all its promises has never produced a single gallon of its promised fuel after eight years of trying to get its Sierra plant operational. Meanwhile, the reality of this garbage (from outside of Gary)-to-fuel plan is that approximately 125 trucks daily will make round trips down Cline Ave and the feedstock they carry will be one-third plastic waste.

If there should ever be a fire at the site, (as there was only last year at a plant also using gasification technology in Ashley, Indiana), burning plastic produces dioxin, a cancer-causing toxic chemical. And, Fulcrum has no comprehensive environmental response plan with first responders in case of any accident, spill, fire or other incident.

The cheerleaders for Fulcrum have made it very clear that once again they are willing to trade the known environmental health impacts on the people of Gary for pie-in-the-sky promises from a company that hasn't shown it is capable of making good on any of them.

It's time to say enough. IDEM must defer its decision on Fulcrum's air permit application until the Sierra plant has become fully operational and is actually producing the jet fuel it says it can.

Lin Kaatz Chary, member, GARD (Gary Advocates for Responsible Development)

IDEM Response to Comment 23:

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Andrew Belt, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-3217 or (800) 451-6027, and ask for Andrew Belt or (317) 232-3217.

(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 Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
PTE Summary

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Uncontrolled Potential to Emit (tons/yr)									
Emissions Unit	**PM**	**PM10**	**PM2.5 ***	**SO_2**	**NOx**	**VOC**	**CO**	**H_2S**	**Total HAPs****
Feedstock Storage and Handling	810.93	810.93	810.93	-	-	-	-	-	-
Feedstock Dryers	314.96	314.96	314.96	0.24	12.11	2.18	14.94	-	0.75
Silo Emissions	28.74	28.74	28.74	-	-	-	-	-	-
Pulse Combustors	7.40	7.40	7.40	0.58	88.56	5.52	40.87	-	1.84
Sulfur Removal Unit Vent	-	-	-	-	-	-	-	10.47	-
FT Reactor	-	-	-	-	-	1,345.13	-	-	-
Utility Boiler	8.94	8.94	8.94	1.75	45.10	5.01	46.35	-	2.32
Storage Tanks	-	-	-	-	-	10.16	-	-	-
Fire Pump Engine	0.03	0.03	0.03	8.15E-04	0.66	0.25	0.57	-	3.97E-03
Emergency Generator	0.33	0.33	0.33	0.01	10.60	0.71	5.79	-	0.04
Cooling Tower	0.69	0.69	0.69	-	-	-	-	-	-
Wastewater Treatment System	-	-	-	-	-	18.62	-	-	-
Flare (FLA)	2.20	2.20	2.20	11.07	3.35	21.49	14.91	-	0.06
Truck and Railcar Loadout System & Flare (LOAD)	1.38E-03	4.31E-03	4.31E-03	3.09E-04	0.05	0.43	0.05	-	0.02
Hydrocracker Heater	0.32	0.32	0.32	0.02	4.17	0.23	3.50	-	0.08
Fractionator Heater	0.32	0.32	0.32	0.02	4.17	0.23	3.50	-	0.08
Product Stripper Heater	0.12	0.12	0.12	0.01	1.59	0.09	1.33	-	0.03
Total Excluding Fugitives	**1,174.98**	**1,174.98**	**1,174.98**	**13.72**	**170.35**	**1,410.04**	**131.82**	**10.47**	**-- ****
Fugitive Emissions									
Paved Roads	7.94	1.59	0.39	-	-	-	-	-	-
Slag Handling Activities	*0.04*	*0.02*	*2.96E-03*	-	-	-	-	-	-
Component Leaks	-	-	-	-	-	*19.06*	-	-	0.15
Total Fugitives	*7.98*	*1.61*	*0.39*	*0.00*	*0.00*	*19.06*	*0.00*	*0.00*	*0.15*
Total Including Fugitives	**1,182.96**	**1,176.59**	**1,175.37**	**13.72**	**170.35**	**1,429.10**	**131.82**	**10.47**	**-- ****

** PM2.5 listed is direct PM2.5*
***Fugitive HAP emissions are always included in the source-wide emissions**

Source-Wide Total HAPs: 5.36

Potential to Emit after Issuance (tons/yr)									
Emissions Unit	**PM**	**PM10**	**PM2.5 ***	**SO_2**	**NOx**	**VOC**	**CO**	**H_2S**	**Total HAPs****
Feedstock Storage and Handling	168.98	37.19	18.66	-	-	-	-	-	-
FT Reactor	-	-	-	-	-	48.12	-	-	-
Feedstock Dryers	15.75	15.75	15.75	0.24	41.91		83.69	-	0.75
Pulse Combustors	7.40	7.40	7.40	0.58				-	1.84
Utility Boiler	8.94	8.94	8.94	1.75				-	2.32
Flare (FLA)	2.20	2.20	2.20	11.07				-	0.06
Hydrocracker Heater	0.32	0.32	0.32	0.02				-	0.08
Fractionator Heater	0.32	0.32	0.32	0.02				-	0.08
Product Stripper Heater	0.12	0.12	0.12	0.01				-	0.03
Wastewater Treatment System	-	-	-	-	-		-	-	-
Storage Tanks	-	-	-	-	-		-	-	-
Fire Pump Engine	0.03	0.03	0.03	0.00	0.13	0.05	0.57	-	3.97E-03
Emergency Generator	0.33	0.33	0.33	0.01	2.12	0.14	5.79	-	0.04
Silo Emissions	1.44	1.44	1.44	-	-	-	-	-	-
Sulfur Removal Unit Vent	-	-	-	-	-	-	-	10.47	-
Cooling Tower	0.69	0.69	0.69	-	-	-	-	-	-
Truck and Railcar Loadout System & Flare (LOAD)	1.38E-03	4.31E-03	4.31E-03	3.09E-04	0.05	0.43	0.05	-	0.02
Total Excluding Fugitives	**206.52**	**74.73**	**56.20**	**13.72**	**44.21**	**48.73**	**90.10**	**10.47**	**-- ****
Fugitive Emissions									
Paved Roads	*7.94*	*1.59*	*0.39*	-	-	-	-	-	-
Slag Handling Activities	*0.04*	*0.02*	*0.00*	-	-	-	-	-	-
Component Leaks	-	-	-	-	-	*19.06*	-	-	*0.15*
Total Fugitives	*7.98*	*1.61*	*0.39*	*0.00*	*0.00*	*19.06*	*0.00*	*0.00*	*0.15*
Total Including Fugitives	**214.50**	**76.33**	**56.59**	**13.72**	**44.21**	**67.80**	**90.10**	**10.47**	**-- ****

** PM2.5 listed is direct PM2.5*
***Fugitive HAP emissions are always included in the source-wide emissions**
Note: The gray shaded cells indicate where limits are included.

Source-Wide Total HAPs: 5.36

Appendix A: Emission Calculations
Feedstock Storage & Handling and Feedstock Dryer Baghouse Emissions

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameter	Unit	Baghouse for Feedstock Storage and Transfer to Feed Bins [a]	Baghouses for Feedstock Drying [b,c]
Exhaust Gas Flow Rate	ft^3/min	216,000	71,993
Outlet PM Loading	grains/ft^3	0.005	0.0058
Annual Operation	hrs/yr	8760	8760
Hourly PM Emissions (Uncontrolled)	lb/hr	185.14	71.91
Annual PM Emissions (Uncontrolled)	tons/yr	810.93	314.96
Individual Hourly PM Emissions (Controlled)	lb/hr	3.09	1.20
Individual Annual PM Emissions (Controlled)	tons/yr	13.52	5.25
Total Hourly PM Emissions (Controlled)	lb/hr	9.26	3.60
Total Annual PM Emissions (Controlled)	tons/yr	40.55	15.75
Individual Hourly PM Emissions (Limited)	lb/hr	12.86	1.20
Individual Annual PM Emissions (Limited)	tons/yr	56.33	5.25
Total Hourly PM Emissions (Limited)	lb/hr	38.58	3.60
Total Annual PM Emissions (Limited)	tons/yr	168.98	15.75
Individual Hourly PM10 Emissions (Limited)	lb/hr	2.83	1.20
Individual Annual PM10 Emissions (Limited)	tons/yr	12.40	5.25
Total Hourly PM10 Emissions (Limited)	lb/hr	8.49	3.60
Total Annual PM10 Emissions (Limited)	tons/yr	37.19	15.75
Individual Hourly PM2.5 Emissions (Limited)	lb/hr	1.42	1.20
Individual Annual PM2.5 Emissions (Limited)	tons/yr	6.22	5.25
Total Hourly PM2.5 Emissions (Limited)	lb/hr	4.26	3.60
Total Annual PM2.5 Emissions (Limited)	tons/yr	18.66	15.75

Notes:
[a] Data provided by Fulcrum Centerpoint
[b] Outlet dust loading based on input load of 0.78 lb/Mmbtu per Vendor (Earth Care)
Exhaust flowrate = 71,993 x 3 = 215,979 ACFM
[c]Baghouse Removal Efficiency based on Baghouse Vendor guarantee of clean gas value <10mg/m3 and inlet load of 0.78 lb/mmbtu
Removal Efficiency = 95.0%
Assume PM=PM10=PM2.5 unless otherwise noted

Appendix A: Emission Calculations
Feedstock Dryer

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)[c]	Number of Dryers	Emission Factors	Units	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
Nitrogen Oxides (NO_X)[a]	30.73	3	0.030	lb/mmbtu	1,020	8,760	2.77	12.11
Carbon Monoxide (CO)[a]	30.73	3	0.037	lb/mmbtu	1,020	8,760	3.41	14.94
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)[b]	30.73	3	0.78	lb/mmbtu	1,020	8,760	71.91	314.96
Sulfur Dioxide (SO2)[d]	30.73	3	0.6	lb/MMscf	1,020	8,760	0.05	0.24
Volatile Organic Compounds (VOC)[d]	30.73	3	5.5	lb/MMscf	1,020	8,760	0.50	2.18

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factors (lb/MMscf) [d]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
2-Methylnaphthalene	91-57-6	92.19	2.40E-05	1,020	8,760	2.17E-06	9.50E-06
3-Methylchloranthrene	56-49-5	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
7,12-Dimethylbenz(a)anthracene	57-97-6	92.19	1.60E-05	1,020	8,760	1.45E-06	6.33E-06
Acenaphthene	83-32-9	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Acenaphthylene	203-96-8	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Anthracene	120-12-7	92.19	2.40E-06	1,020	8,760	2.17E-07	9.50E-07
Benz(a)anthracene	56-55-3	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Benzene	71-43-2	92.19	2.10E-03	1,020	8,760	1.90E-04	8.31E-04
Benzo(a)pyrene	50-32-8	92.19	1.20E-06	1,020	8,760	1.08E-07	4.75E-07
Benzo(b)fluoranthene	205-99-2	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Benzo(g,h,i)perylene	191-24-2	92.19	1.20E-06	1,020	8,760	1.08E-07	4.75E-07
Benzo(k)fluoranthene	207-08-9	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Chrysene	218-01-9	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Dibenz(a,h)anthracene	53-70-3	92.19	1.20E-06	1,020	8,760	1.08E-07	4.75E-07
Dichlorobenzene	25321-22-6	92.19	1.20E-03	1,020	8,760	1.08E-04	4.75E-04
Fluoranthene	206-44-0	92.19	3.00E-06	1,020	8,760	2.71E-07	1.19E-06
Fluorene	86-73-7	92.19	2.80E-06	1,020	8,760	2.53E-07	1.11E-06
Formaldehyde	50-00-0	92.19	7.50E-02	1,020	8,760	6.78E-03	0.03
Hexane	110-54-3	92.19	1.80E+00	1,020	8,760	1.63E-01	0.71
Indeno(1,2,3-cd)pyrene	193-39-5	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Naphthalene	91-20-3	92.19	6.10E-04	1,020	8,760	5.51E-05	2.41E-04
Phenanthrene	85-01-8	92.19	1.70E-05	1,020	8,760	1.54E-06	6.73E-06
Pyrene	129-00-0	92.19	5.00E-06	1,020	8,760	4.52E-07	1.98E-06
Toluene	108-88-3	92.19	3.40E-03	1,020	8,760	3.07E-04	1.35E-03
Arsenic	7440-38-2	92.19	2.00E-04	1,020	8,760	1.81E-05	7.92E-05
Beryllium	7440-41-7	92.19	1.20E-05	1,020	8,760	1.08E-06	4.75E-06
Cadmium	7440-43-9	92.19	1.10E-03	1,020	8,760	9.94E-05	4.35E-04
Chromium	7440-47-3	92.19	1.40E-03	1,020	8,760	1.27E-04	5.54E-04
Cobalt	7440-48-4	92.19	8.40E-05	1,020	8,760	7.59E-06	3.33E-05
Manganese	7439-96-5	92.19	3.80E-04	1,020	8,760	3.43E-05	1.50E-04
Mercury	7439-97-6	92.19	2.60E-04	1,020	8,760	2.35E-05	1.03E-04
Nickel	7440-02-0	92.19	2.10E-03	1,020	8,760	1.90E-04	8.31E-04
Selenium	7782-49-2	92.19	2.40E-05	1,020	8,760	2.17E-06	9.50E-06
Total HAPs						0.17	0.75

Notes:
[a] Emission Factors for NOx and CO by Vendor (Earth Care) for Low NOx burners.
[b] Emission Factors for PM and SO2 by Vendor (Earth Care)
[c] Heat input of 30.73 Mmbtu/hr per burner by Vendor (Earth Care)
[d] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2

Appendix A: Emission Calculations
Silos and Hoppers

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameter	Units	Bed Media Silo Baghouses [c]	Ash Silo Baghouses [c]
Exhaust Gas Flow Rate [a]	ft^3/min	3,828	3,828
Outlet PM Loading [b]	grains/ft^3	0.005	0.005
Silo/Hopper Loading Rate	tons/hr	0.23	N/A
Annual Operation[d]	hrs/yr	8,760	8,760
Total Hourly PM/PM10/PM2.5 Emissions (Uncontrolled)	lb/hr	3.28	3.28
Total Annual PM/PM10/PM2.5 Emissions (Uncontrolled)	tons/yr	14.37	14.37
Individual Hourly PM/PM10/PM2.5 Emissions (Controlled/Limited)	lb/hr	0.055	0.055
Individual Annual PM/PM10/PM2.5 Emissions (Controlled/Limited)	tons/yr	0.24	0.24
Total Hourly PM/PM10/PM2.5 Emissions (Controlled/Limited)	lb/hr	0.16	0.16
Total Annual PM/PM10/PM2.5 Emissions (Controlled/Limited)	tons/yr	0.72	0.72

Notes:
[a] Data provided by Fulcrum Centerpoint
[b] Outlet dust loading based on expected levels for the silo filters provided by Fulcrum Centerpoint
[c] Emission estimated based on the exhaust gas flow rates of the silo filters.
Control efficiency is estimated at 95%

Appendix A: Emission Calculations
Slag Handling Activities

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Activity	Type of Operation	Hourly Throughput (ton/hr)	Annual Operating Hours (hrs/year)	Annual Throughput (tons/year)	M - Moisture Content [a] (%)	U - Wind Speed [b] (mph)	Uncontrolled Emission Factor [c]			Hourly Emissions [c]			Annual Emissions [c]		
							PM (lb/ton)	PM_{10} (lb/ton)	$PM_{2.5}$ (lb/ton)	PM (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)
Slag Handling	Batch Drop	0.525	8,760	4,599	0.92	10.3	0.01797	0.00850	0.00129	0.0094	0.0045	0.0007	0.0413	0.0195	0.0030

Notes:
[a] Based on Table 13.4.2-1 of AP-42 (for iron and steel production slag material).
[b] Average hourly wind speed for Chicago, Illinois
[c] Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 2006) Section 13.2.4:
E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM, 0.35 for PM_{10}, and .053 for $PM_{2.5}$.

Appendix A: Emission Calculations
Pulse Combustors

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Number of Units	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
		lb/MMscf [a]	lb/MMBtu [b]					
Nitrogen Oxides (NOx)[c]	75.6	--	0.089	3	1020	8760	20.22	88.56
Carbon Monoxide (CO)[c]	75.6	--	0.041	3	1020	8760	9.33	40.87
Particulate Matters (PM/PM10/PM2.5)	75.6	7.60	--	3	1020	8760	1.69	7.40
Sulfur Dioxide (SO2)	75.6	0.60	--	3	1020	8760	0.13	0.58
Volatile Organic Compounds (VOC)	75.6	--	0.00556	3	1020	8760	1.26	5.52

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [d]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
2-Methylnaphthalene	91-57-6	226.8	2.40E-05	1020	8760	5.34E-06	2.34E-05
3-Methylchloranthrene	56-49-5	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
7,12-Dimethylbenz(a)anthracene	57-97-6	226.8	1.60E-05	1020	8760	3.56E-06	1.56E-05
Acenaphthene	83-32-9	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Acenaphthylene	203-96-8	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Anthracene	120-12-7	226.8	2.40E-06	1020	8760	5.34E-07	2.34E-06
Benz(a)anthracene	56-55-3	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Benzene	71-43-2	226.8	2.10E-03	1020	8760	4.67E-04	2.05E-03
Benzo(a)pyrene	50-32-8	226.8	1.20E-06	1020	8760	2.67E-07	1.17E-06
Benzo(b)fluoranthene	205-99-2	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Benzo(g,h,i)perylene	191-24-2	226.8	1.20E-06	1020	8760	2.67E-07	1.17E-06
Benzo(k)fluoranthene	207-08-9	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Chrysene	218-01-9	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Dibenz(a,h)anthracene	53-70-3	226.8	1.20E-06	1020	8760	2.67E-07	1.17E-06
Dichlorobenzene	25321-22-6	226.8	1.20E-03	1020	8760	2.67E-04	1.17E-03
Fluoranthene	206-44-0	226.8	3.00E-06	1020	8760	6.67E-07	2.92E-06
Fluorene	86-73-7	226.8	2.80E-06	1020	8760	6.23E-07	2.73E-06
Formaldehyde	50-00-0	226.8	7.50E-02	1020	8760	1.67E-02	0.07
Hexane	110-54-3	226.8	1.80E+00	1020	8760	4.00E-01	1.75
Indeno(1,2,3-cd)pyrene	193-39-5	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Naphthalene	91-20-3	226.8	6.10E-04	1020	8760	1.36E-04	5.94E-04
Phenanthrene	85-01-8	226.8	1.70E-05	1020	8760	3.78E-06	1.66E-05
Pyrene	129-00-0	226.8	5.00E-06	1020	8760	1.11E-06	4.87E-06
Toluene	108-88-3	226.8	3.40E-03	1020	8760	7.56E-04	3.31E-03
Arsenic	7440-38-2	226.8	2.00E-04	1020	8760	4.45E-05	1.95E-04
Beryllium	7440-41-7	226.8	1.20E-05	1020	8760	2.67E-06	1.17E-05
Cadmium	7440-43-9	226.8	1.10E-03	1020	8760	2.45E-04	1.07E-03
Chromium	7440-47-3	226.8	1.40E-03	1020	8760	3.11E-04	1.36E-03
Cobalt	7440-48-4	226.8	8.40E-05	1020	8760	1.87E-05	8.18E-05
Manganese	7439-96-5	226.8	3.80E-04	1020	8760	8.45E-05	3.70E-04
Mercury	7439-97-6	226.8	2.60E-04	1020	8760	5.78E-05	2.53E-04
Nickel	7440-02-0	226.8	2.10E-03	1020	8760	4.67E-04	2.05E-03
Selenium	7782-49-2	226.8	2.40E-05	1020	8760	5.34E-06	2.34E-05
Total HAPs						0.42	1.84

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors are based on Vendor provided lb/hr values for 75.6 MMBtu/hr design
[c] Emissions based on SCR Control efficiency of 90% for NOx
[d] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4

Appendix A: Emission Calculations
Natural Gas and Purge Gas Combustion
MMBTU/HR >100
Fischer Tropsch (FT) Synthesis Reactor and Utility Boiler

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

1. Utility Boiler

Regulated Air Pollutants	Natural Gas Only Firing					Combination Natural Gas and Purge Gas Firing											Any Fuel	
						Natural Gas Firing			Purge Gas Firing				Total					
	Emission Factor [a]	Heat Input [b]	Maximum Emissions	Operating Hours	Unlimited Emissions	Emission Factor [a]	Heat Input [d]	Maximum Emissions	Emission Factor [c]	Heat Input [d]	Control Efficiency[e]	Maximum Emissions	Hourly Emissions	Operating Hours	Unlimited Emissions	Controlled Emissions	Unlimited Emissions	Controlled Emissions
	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)	(hrs/yr)	(tons/yr)	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)	(lb/MMBtu)	(MMBtu/hr)	(%)	(lb/hr)	(lb/hr)	(hrs/yr)	(tons/yr)	(tons/yr)	(tons/yr)	(tons/yr)
Nitrogen Oxides (NOx)[f]	0.036	286.0	10.30	8,760	45.10	0.036	249.20	8.97	0.036	36.80	83.00	1.32	10.30	8,760	45.10	7.67	45.10	7.67
Carbon Monoxide (CO)[g]	0.037	286.0	10.58	8,760	46.35	0.037	249.20	9.22	0.037	36.80	90.00	1.36	10.58	8,760	46.35	4.63	46.35	4.63
Particulate (PM/PM10/PM2.5)	0.007	286.0	2.00	8,760	8.77	0.007	249.20	1.74	0.008	36.80	0.00	0.30	2.04	8,760	8.94	8.94	8.94	8.94
Sulfur Dioxide (SO2)	0.001	286.0	0.40	8,760	1.75	0.001	249.20	0.35	--	36.80	0.00	3.68E-04	0.35	8,760	1.53	1.53	1.75	1.75
Volatile Organic Compounds (VOC)	0.004	286.0	1.14	8,760	5.01	0.004	249.20	1.00	0.004	36.80	96.00	0.15	1.14	8,760	5.01	4.39	5.01	4.39
Sulfuric Acid Mist (SAM)	--	286.0	0.06	8,760	0.27	0.002	249.20	0.43	--	36.80	0.00	5.64E-05	0.43	8,760	1.87	1.87	1.87	1.87

[a] Natural gas-firing emissions factors -
NOx, CO, PM, VOC = Vendor (Cleaver Brooks) Estimate
SO2 = Vendor (Victory Energy) Estimate (based on 1 grain/100 SCF sulfur in fuel, assuming 100% conversion of fuel sulfur to SO2)
SAM = Assuming 10% of SO2 converts into SAM

[b] Heat input based on boiler design data from vendor (Cleaver Brooks) for a 200,000 lb/hr steam flow.

[c] Purge gas-firing emissions factors -
NOx and CO = Vendor (Cleaver Brooks) Estimate (using Natural Gas)
PM = 8.2 lb/10^6 scf CH4 (Table 2.4-5, AP-42 Section 2.4)
SO2 : Based on H2S content of 0.0352 ppmw
VOC = 55,300.00 ppmw
0.004 lb/MMBtu - Vendor (Cleaver Brooks) Estimate
Vendor assured the 0.004 lb/MMBtu emission factor could be achieved for both combusting natural gas and purge gas.
SAM - Assuming 10% of SO2 converts into SAM

[d] Maximum heat input from purge gas and the remaining is from natural gas.
Purge gas heat content = 6,612.26 Btu/lb
Purge gas flow = 5,553.48 lb/hr
Purge gas MW = 22.23 lb/lb-mol
Purge gas volume flow = 96,338.15 scf/hr
Purge gas density = 0.0576 lb/scf
Purge gas heat content = 381.17 Btu/scf

[e] VOC in purge gas assumed to be 96% destroyed during Purge gas combustion in burner (based on AP-42 Section 2.4)

[f] SCR control efficicency of 83% for NOx

[g] Oxidation catalyst system control efficiency of 90% for CO

2. FT Reactor

FT Reactor Purge Gas PTE		
Purge Flow	5,553.48	lb/hr
	2.78	tons/hr
	24,324.23	tons/yr
VOC Content	55,300.00	ppmw
VOC %	5.530%	
VOC Total	1,345.13	tons/yr
Control Efficiency	99.60%	
Controlled VOC Total	5.38	tons/yr

Purge Gas Cost Savings		
Hourly Heat Input	36.72	MMBtu/hr
Annual Heat Input	321,667.20	MMBtu/yr
Convert to Therms	3,217,440.97	therm/yr
Nipsco Natural Gas Price	$ 0.51	$/therm
Total Annual Savings	$ 1,640,894.89	$/yr

Appendix A: Emission Calculations
Natural Gas and Purge Gas Combustion
MMBTU/HR >100
Utility Boiler

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Hazardous Air Pollutants	CAS Number	Natural Gas Only Firing					Combination Natural Gas and Purge Gas Firing									Maximum Annual Emissions Any Fuel (tons/yr)
							Natural Gas Firing			Purge Gas Firing						
		Emission Factor [a] (lb/MMScf)	Heat Input [b] (MMBtu/hr)	Maximum Emissions [c] (lb/hr)	Operating Hours (hrs/yr)	Annual Emissions (tons/yr)	Emission Factor (lb/MMScf)	Heat Input [d] (MMBtu/hr)	Maximum Emissions [c] (lb/hr)	Emission Factor [e] (lb/MMscf)	Heat Input [d] (MMBtu/hr)	Maximum Emissions[c] (lb/hr)	Total Hourly Emissions (lb/hr)	Operating Hours (hrs/yr)	Annual Emissions (tons/yr)	
2-Methylnaphthalene	91-57-6	2.40E-05	286.0	6.73E-06	8,760	2.95E-05	2.40E-05	249.2	5.86E-06	-	36.8	-	5.86E-06	8,760	2.57E-05	2.95E-05
3-Methylchloranthrene	56-49-5	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	286.0	4.49E-06	8,760	1.96E-05	1.60E-05	249.2	3.91E-06	-	36.8	-	3.91E-06	8,760	1.71E-05	1.96E-05
Acenaphthene	83-32-9	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Acenaphthylene	203-96-8	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Anthracene	120-12-7	2.40E-06	286.0	6.73E-07	8,760	2.95E-06	2.40E-06	249.2	5.86E-07	-	36.8	-	5.86E-07	8,760	2.57E-06	2.95E-06
Benz(a)anthracene	56-55-3	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Benzene	71-43-2	2.10E-03	286.0	5.89E-04	8,760	2.58E-03	2.10E-03	249.2	5.13E-04	-	36.8	-	5.13E-04	8,760	2.25E-03	2.58E-03
Benzo(a)pyrene	50-32-8	1.20E-06	286.0	3.36E-07	8,760	1.47E-06	1.20E-06	249.2	2.93E-07	-	36.8	-	2.93E-07	8,760	1.28E-06	1.47E-06
Benzo(b)fluoranthene	205-99-2	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Benzo(g,h,i)perylene	191-24-2	1.20E-06	286.0	3.36E-07	8,760	1.47E-06	1.20E-06	249.2	2.93E-07	-	36.8	-	2.93E-07	8,760	1.28E-06	1.47E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Chrysene	218-01-9	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Dibenz(a,h)anthracene	53-70-3	1.20E-06	286.0	3.36E-07	8,760	1.47E-06	1.20E-06	249.2	2.93E-07	-	36.8	-	2.93E-07	8,760	1.28E-06	1.47E-06
Dichlorobenzene	25321-22-6	1.20E-03	286.0	3.36E-04	8,760	1.47E-03	1.20E-03	249.2	2.93E-04	-	36.8	-	2.93E-04	8,760	1.28E-03	1.47E-03
Fluoranthene	206-44-0	3.00E-06	286.0	8.41E-07	8,760	3.68E-06	3.00E-06	249.2	7.33E-07	-	36.8	-	7.33E-07	8,760	3.21E-06	3.68E-06
Fluorene	86-73-7	2.80E-06	286.0	7.85E-07	8,760	3.44E-06	2.80E-06	249.2	6.84E-07	-	36.8	-	6.84E-07	8,760	3.00E-06	3.44E-06
Formaldehyde	50-00-0	7.50E-02	286.0	2.10E-02	8,760	9.21E-02	7.50E-02	249.2	1.83E-02	-	36.8	-	1.83E-02	8,760	8.03E-02	0.09
Hexane	110-54-3	1.80E+00	286.0	5.05E-01	8,760	2.21E+00	1.80E+00	249.2	4.40E-01	-	36.8	-	4.40E-01	8,760	1.93E+00	2.21
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Naphthalene	91-20-3	6.10E-04	286.0	1.71E-04	8,760	7.49E-04	6.10E-04	249.2	1.49E-04	-	36.8	-	1.49E-04	8,760	6.53E-04	7.49E-04
Phenanthrene	85-01-8	1.70E-05	286.0	4.77E-06	8,760	2.09E-05	1.70E-05	249.2	4.15E-06	-	36.8	-	4.15E-06	8,760	1.82E-05	2.09E-05
Pyrene	129-00-0	5.00E-06	286.0	1.40E-06	8,760	6.14E-06	5.00E-06	249.2	1.22E-06	-	36.8	-	1.22E-06	8,760	5.35E-06	6.14E-06
Toluene	108-88-3	3.40E-03	286.0	9.53E-04	8,760	4.18E-03	3.40E-03	249.2	8.31E-04	-	36.8	-	8.31E-04	8,760	3.64E-03	4.18E-03
Arsenic	7440-38-2	2.00E-04	286.0	5.61E-05	8,760	2.46E-04	2.00E-04	249.2	4.89E-05	-	36.8	-	4.89E-05	8,760	2.14E-04	2.46E-04
Beryllium	7440-41-7	1.20E-05	286.0	3.36E-06	8,760	1.47E-05	1.20E-05	249.2	2.93E-06	-	36.8	-	2.93E-06	8,760	1.28E-05	1.47E-05
Cadmium	7440-43-9	1.10E-03	286.0	3.08E-04	8,760	1.35E-03	1.10E-03	249.2	2.69E-04	-	36.8	-	2.69E-04	8,760	1.18E-03	1.35E-03
Chromium	7440-47-3	1.40E-03	286.0	3.93E-04	8,760	1.72E-03	1.40E-03	249.2	3.42E-04	-	36.8	-	3.42E-04	8,760	1.50E-03	1.72E-03
Cobalt	7440-48-4	8.40E-05	286.0	2.36E-05	8,760	1.03E-04	8.40E-05	249.2	2.05E-05	-	36.8	-	2.05E-05	8,760	8.99E-05	1.03E-04
Manganese	7439-96-5	3.80E-04	286.0	1.07E-04	8,760	4.67E-04	3.80E-04	249.2	9.28E-05	-	36.8	-	9.28E-05	8,760	4.07E-04	4.67E-04
Mercury	7439-97-6	2.60E-04	286.0	7.29E-05	8,760	3.19E-04	2.60E-04	249.2	6.35E-05	-	36.8	-	6.35E-05	8,760	2.78E-04	3.19E-04
Nickel	7440-02-0	2.10E-03	286.0	5.89E-04	8,760	2.58E-03	2.10E-03	249.2	5.13E-04	-	36.8	-	5.13E-04	8,760	2.25E-03	2.58E-03
Selenium	7782-49-2	2.40E-05	286.0	6.73E-06	8,760	2.95E-05	2.40E-05	249.2	5.86E-06	-	36.8	-	5.86E-06	8,760	2.57E-05	2.95E-05
Methanol	67-56-1	--	--	--	--	--	--	249.2	-	3.53E-02	36.8	1.30E-06	1.30E-06	8,760	5.69E-06	5.69E-06
POH	--	--	--	--	--	--	--	249.2	-	1.80E-02	36.8	6.61E-07	6.61E-07	8,760	2.89E-06	2.89E-06
Total HAPs																2.32

Notes:
[a] Natural gas-firing emissions factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[b] Heat input based on boiler design data.
[c] For Emission estimation, used heat content of natural gas and purge gas as 1020 and 381.6 Btu/scf respectively
[d] Maximum heat input from purge gas and the remaining is from natural gas.
[e] Purge Gas-firing emissions factors were estimated based on mole fraction of the compounds (Fulcrum Centerpoint design data).

Appendix A: Emission Calculations
Sulfur Removal Unit (SRU) Vent

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameters	Units	Value
Total Exhaust Gas Flow Rate [a]	lbmol/hr	3,514
H2S concentration in exhaust gas [b]	ppmv	20
No. of moles of H2S	lbmol/hr	0.070
Annual Operating Hours	hrs/yr	8760
Hourly H2S Emissions [c]	lb/hr	2.39
Annual H2S Emissions	tons/yr	10.47

Notes:

[a] Exhaust gas flow rate based on Fulcrum Centerpoint design data (CO2 vent from Aspen Model)

[b] The vendor guaranteed H2S concentration in the SRU exhaust gas (CO2 vent) is 10 ppmv. A H2S concentration value of 20 ppmv is used in the permit as the response step threshold value. The worst case potential to emit (PTE) of H2S from the SRU is calculated assuming a H2S concentration of 20 ppmv.

[c] Hourly H2S Emissions (lb/hr) = Molar Flow (lbmol/hr) X Molecular weight of H2S (34 lbs/lbmol)

Appendix A: Emission Calculations
Flare (FLA)

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameters [a]	Pilot Gas	Startup (SU)		Shutdown (SD)		
		Flare SU Stream After Scrubber	Flare SU Stream After Amine System	Flare SD Stream Before Compressor (Low Pressure)	Flare SD Stream After Compressor (High Pressure)	Flare SD Stream - Draining & Inspecting (Naptha)
Gas flow rate to Flare (scfm)	1.915	--	-	--	--	--
Annual gas flow rate to Flare (MMscf/yr)	1.01	--	-	--	--	--
Gas heating value (Btu/ft3, HHV)	1020	239.00	304.00			
Gas heating value (Btu/lb, HHV)	--	--	-	4,347.66	6,612.26	20,587.00
Total annual flaring event	Continuous	6.00	1.00	12.00	12.00	4.00
Duration of flaring event (hrs)	--	12.00	12.00	0.25	2.00	12.00
Gas flow during flaring event (lb/hr)	--	248,252.00	106,371.00	4,583.00	27,903.00	102.76
Gas molecular weight (lb/lb-mol)	--	21.17	11.26	21.17	43.30	125.00
Hourly heat input (MMBtu/hr)	0.12	1,080.59	1,107.04	19.93	184.50	2.12
Annual hours of operation	8760	72.00	12.00	3.00	24.00	48.00
Annual heat input (MMBtu/yr)	1026.7	77,802.14	13,284.54	59.78	4,428.04	101.55

Regulated Air Pollutants	Pilot Gas Combustion		
	Emission Factor [b]	Units	Annual Emisisons (tons/yr)
Carbon Monoxide (CO)	84	lb/MMscf	0.042
Nitrogen Oxides (NOx)	100	lb/MMscf	0.050
Particulate Matter (PM)	7.6	lb/MMscf	0.004
Particulate Matter (PM10)	7.6	lb/MMscf	0.004
Particulate Matter (PM2.5)	7.6	lb/MMscf	0.004
Volatile Organic Compounds (VOC)	5.5	lb/MMscf	0.003
Sulfur Dioxide (SO2)	0.6	lb/MMscf	0.000

Regulated Air Pollutants	Flare SU - after scrubber'		Flare SU - after Amine		Flare SD - Low Pressure		Flare SD -High Pressure'		Flare SD - Draining & Inpecting		Total Annual Emisisons from SU & SD events (tons/yr)
	Emission Factor(lb/MMBtu) [c]	Annual Emisisons from SU after scrubber (tons/yr)	Emission Factor (lb/MMBtu)	Annual Emisisons from SU Events (tons/yr)	Emission Factor (lb/MMBtu) [c]	Annual Emisisons from SU Events (tons/yr)	Emission Factor (lb/MMBtu) [c]	Annual Emisisons from SU after scrubber (tons/yr)	Emission Factor (lb/MMBtu) [c]	Annual Emisisons from SU Events (tons/yr)	
Carbon Monoxide (CO)	0.31	12.059	0.310	2.059	0.310	0.686	0.31	0.009	0.310	0.016	14.87
Nitrogen Oxides (NOx)	0.068	2.645	0.068	0.452	0.068	0.151	0.068	0.002	0.068	0.003	3.30
Particulate Matter (PM)	0.0478	1.859	0.038	0.249	0.038	0.083	0.038	0.001	0.038	0.002	2.20
Particulate Matter (PM10)	0.0478	1.859	0.038	0.249	0.038	0.083	0.038	0.001	0.038	0.002	2.20
Particulate Matter (PM2.5)	0.0478	1.859	0.038	0.249	0.038	0.083	0.038	0.001	0.038	0.002	2.20
Volatile Organic Compounds (VOC)	0.14	5.446	0.140	0.930	0.140	0.310	0.14	0.004	0.140	0.007	6.70
Sulfur Dioxide (SO2)	0.2683	10.438	0.003	0.018	0.278	0.614	0.0000	0.000	0.000	0.000	11.07

FLARE POTENTIAL TO EMIT CALCULATIONS

Parameters [a]	Pilot Gas	Startup (SU)		Shutdown (SD)		
		Flare SU Stream After Scrubber	Flare SU Stream After Amine System	Flare SD Stream Before Compressor (Low Pressure)	Flare SD Stream After Compressor (High Pressure)	Flare SD Stream - Draining & Inspecting (Naptha)
Gas flow rate to Flare (scfm)	1.915	--	-	--	--	--
Annual gas flow rate to Flare (MMscf/yr)	1.0	--	-	--	--	--
Gas heating value (Btu/ft3, HHV)	1020.0	239.00	304.00			0.00
Gas heating value (Btu/lb, HHV)	--	--	-	4,347.66	6,612.26	20,587.00
Total annual flaring event	Continuous	6.00	1.00	12.00	12.00	4.00
Duration of flaring event (hrs)	--	12.00	12.00	0.25	2.00	12.00
Gas flow during flaring event (lb/hr)	--	248,252.00	106,371.00	4,583.00	27,903.00	102.76
Gas molecular weight (lb/lb-mol)	--	21.17	11.26	21.17	43.30	125.00
Hourly heat input (MMBtu/hr)	0.1	1,080.59	1,107.04	19.93	184.50	2.12
Annual hours of operation	8760.0	72.00	12.00	3.00	24.00	48.00
Annual heat input (MMBtu/yr)	1026.7	77,802.14	13,284.54	59.78	4,428.04	101.55
VOC wt%		0.000%	0.030%	0.000%	0.030%	5.5%
VOC flow during flaring event (lb/hr)		0.00	32.08	0.00	8.41	5.68
VOC flow during flaring event (lb/yr)		0.00	384.94	0.00	201.96	272.85
VOC flow during flaring event (tons/yr)		0.00	0.19	0.00	0.10	0.14

Total Flare PTE (ton/yr)	**21.49**

Notes:
[a] Data based on design specifications provided by Fulcrum Centerpoint.
[b] Natural gas firing emissions factors based on Chapter 1.4, AP-42.
[c] CO, NOx, and VOC emissions factors based on Chapter 13.5, AP-42. PM emissions factors based on Fulcrum Centerpoint estimate of soot content of 40 ug/L in a lightly smoking flare.
SO2 emissions estimated based on Fulcrum Centerpoint design data.

The number of flare events differ between the different processes because there are scenarios where small portions of the plant may require de-pressurization, but the entire plant will not require a full start-up to bring operations back online.
The Btu/lb amounts change between suction and discharge because of the syngas clean up happening in this stage. The labels of "before" and "after" the compressor are mainly to designate the low vs. high pressure portions of the facility. Additional syngas clean-up steps occur between these two "vent to flare" locations. The main one impacting the gas heating value is CO2 removal. CO2 is removed from the syngas between these two stream locations and therefore, the downstream syngas without CO2 has a higher heating value.

Appendix A: Emission Calculations
Flare (FLA) - HAP Emissions

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameters [a]	Pilot Gas	Startup (SU)		Shutdown (SD)		
		Flare SU after scrubber	Flare SU after amine	Flare SD - Low Pressure	Flare SD -High Pressure	Flare SD - Draining & Inspecting
Gas flow rate to Flare (scfm)	1.92	--	-	--	--	--
Annual gas flow rate to Flare (MMscf/yr)	1.01	--	-	--	--	--
Gas heating value (Btu/ft3, HHV)	1,020	239	304			
Gas heating value (Btu/lb, HHV)	--	--	-	4,347.66	6,612.26	20,587.00
Total annual flaring event	Continuous	6.00	6.00	12.00	12.00	4.00
Duration of flaring event (hrs)	--	12.00	12.00	0.25	2.00	12.00
Gas flow during flaring event (lb/hr)	--	248,252	106,371	4,583	55,806	1,292.86
Gas molecular weight (lb/lb-mol)	--	21.17	11.26	21.17	43.30	125.00
Hourly heat input (MMBtu/hr)	0.12	1,080.59	1,107.04	19.93	369.00	26.62
Annual hours of operation	8,760	72.00	72.00	3.00	24.00	48.00
Annual heat input (MMBtu/yr)	1,026.65	77,802.14	79,707.21	59.78	8,856.09	1,277.57

Hazardous Air Pollutants	Pilot Gas Combustion			Syngas Combustion during SU and SD			
	Emission Factor [b]	Units	Annual Emisisons (tons/yr)	Concentration [c] (ppmw)	Annual Emisisons from SU Events (tons/yr)	Annual Emisisons from SD Events (tons/yr)	Total Annual Emisisons (tons/yr)
2-Methylnaphthalene	2.40E-05	lb/MMscf	1.21E-08	--	--	--	1.21E-08
3-Methylchloranthrene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	8.05E-09	--	--	--	8.05E-09
Acenaphthene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Acenaphthylene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Anthracene	2.40E-06	lb/MMscf	1.21E-09	--	--	--	1.21E-09
Benz(a)anthracene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Benzene	2.10E-03	lb/MMscf	1.06E-06	--	--	--	1.06E-06
Benzo(a)pyrene	1.20E-06	lb/MMscf	6.04E-10	--	--	--	6.04E-10
Benzo(b)fluoranthene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	6.04E-10	--	--	--	6.04E-10
Benzo(k)fluoranthene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Chrysene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Dibenz(a,h)anthracene	1.20E-06	lb/MMscf	6.04E-10	--	--	--	6.04E-10
Dichlorobenzene	1.20E-03	lb/MMscf	6.04E-07	--	--	--	6.04E-07
Fluoranthene	3.00E-06	lb/MMscf	1.51E-09	--	--	--	1.51E-09
Fluorene	2.80E-06	lb/MMscf	1.41E-09	--	--	--	1.41E-09
Formaldehyde	7.50E-02	lb/MMscf	3.77E-05	--	--	--	3.77E-05
Hexane	1.80E+00	lb/MMscf	9.06E-04	--	--	--	9.06E-04
Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Naphthalene	6.10E-04	lb/MMscf	3.07E-07	--	--	--	3.07E-07
Phenanthrene	1.70E-05	lb/MMscf	8.56E-09	--	--	--	8.56E-09
Pyrene	5.00E-06	lb/MMscf	2.52E-09	--	--	--	2.52E-09
Toluene	3.40E-03	lb/MMscf	1.71E-06	--	--	--	1.71E-06
Arsenic	2.00E-04	lb/MMscf	1.01E-07	--	--	--	1.01E-07
Beryllium	1.20E-05	lb/MMscf	6.04E-09	--	--	--	6.04E-09
Cadmium	1.10E-03	lb/MMscf	5.54E-07	--	--	--	5.54E-07
Chromium	1.40E-03	lb/MMscf	7.05E-07	--	--	--	7.05E-07
Cobalt	8.40E-05	lb/MMscf	4.23E-08	--	--	--	4.23E-08
Manganese	3.80E-04	lb/MMscf	1.91E-07	--	--	--	1.91E-07
Mercury	2.60E-04	lb/MMscf	1.31E-07	--	--	--	1.31E-07
Nickel	2.10E-03	lb/MMscf	1.06E-06	--	--	--	1.06E-06
Selenium	2.40E-05	lb/MMscf	1.21E-08	--	--	--	1.21E-08
Total HAPs from Syngas flaring [d]	--	--	--	4.02	5.13E-02	2.84E-03	5.41E-02
Total HAPS							**0.06**

[a] Data based on design specifications provided by Fulcrum Centerpoint.
[b] Natural gas-firing HAP emissions factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Concentrations based on Aspen model, Fulcrum Centerpoint data
[d] Assuming 100% of VOC emissions as HAPs. VOC concentration obtained from Fulcrum Centerpoint design data.

Appendix A: Emission Calculations
Hydrocracker Heater

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
		lb/MMscf [a]	lb/MMBtu				
Nitrogen Oxides (NOx)	9.7	100.0	--	1020	8,760	0.95	4.17
Carbon Monoxide (CO)	9.7	84.0	--	1020	8,760	0.80	3.50
Particulate (PM/PM10/PM2.5)	9.7	7.60	--	1020	8,760	0.07	0.32
Sulfur Dioxide (SO2)	9.7	0.60	--	1020	8,760	0.01	0.02
Volatile Organic Compounds (VOC)	9.7	5.50	--	1020	8,760	0.05	0.23

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [b]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
2-Methylnaphthalene	91-57-6	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
3-Methylchloranthrene	56-49-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	9.7	1.60E-05	1020	8,760	1.52E-07	6.66E-07
Acenaphthene	83-32-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Acenaphthylene	203-96-8	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Anthracene	120-12-7	9.7	2.40E-06	1020	8,760	2.28E-08	1.00E-07
Benz(a)anthracene	56-55-3	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzene	71-43-2	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Benzo(a)pyrene	50-32-8	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(b)fluoranthene	205-99-2	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzo(g,h,i)perylene	191-24-2	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(k)fluoranthene	207-08-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Chrysene	218-01-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Dibenz(a,h)anthracene	53-70-3	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Dichlorobenzene	25321-22-6	9.7	1.20E-03	1020	8,760	1.14E-05	5.00E-05
Fluoranthene	206-44-0	9.7	3.00E-06	1020	8,760	2.85E-08	1.25E-07
Fluorene	86-73-7	9.7	2.80E-06	1020	8,760	2.66E-08	1.17E-07
Formaldehyde	50-00-0	9.7	7.50E-02	1020	8,760	7.13E-04	3.12E-03
Hexane	110-54-3	9.7	1.80E+00	1020	8,760	1.71E-02	0.07
Indeno(1,2,3-cd)pyrene	193-39-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Naphthalene	91-20-3	9.7	6.10E-04	1020	8,760	5.80E-06	2.54E-05
Phenanthrene	85-01-8	9.7	1.70E-05	1020	8,760	1.62E-07	7.08E-07
Pyrene	129-00-0	9.7	5.00E-06	1020	8,760	4.75E-08	2.08E-07
Toluene	108-88-3	9.7	3.40E-03	1020	8,760	3.23E-05	1.42E-04
Arsenic	7440-38-2	9.7	2.00E-04	1020	8,760	1.90E-06	8.33E-06
Beryllium	7440-41-7	9.7	1.20E-05	1020	8,760	1.14E-07	5.00E-07
Cadmium	7440-43-9	9.7	1.10E-03	1020	8,760	1.05E-05	4.58E-05
Chromium	7440-47-3	9.7	1.40E-03	1020	8,760	1.33E-05	5.83E-05
Cobalt	7440-48-4	9.7	8.40E-05	1020	8,760	7.99E-07	3.50E-06
Manganese	7439-96-5	9.7	3.80E-04	1020	8,760	3.61E-06	1.58E-05
Mercury	7439-97-6	9.7	2.60E-04	1020	8,760	2.47E-06	1.08E-05
Nickel	7440-02-0	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Selenium	7782-49-2	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
Total HAPs						0.02	0.08

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Emission Factors from 40 CFR 98 Table C-1

Appendix A: Emission Calculations
Fractionator Heater

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
		lb/MMscf [a]	lb/MMBtu				
Nitrogen Oxides (NOx)	9.7	100.0	--	1020	8,760	0.95	4.17
Carbon Monoxide (CO)	9.7	84.0	--	1020	8,760	0.80	3.50
Particulate (PM/PM10/PM2.5)	9.7	7.60	--	1020	8,760	0.07	0.32
Sulfur Dioxide (SO2)	9.7	0.60	--	1020	8,760	0.01	0.02
Volatile Organic Compounds (VOC)	9.7	5.50	--	1020	8,760	0.05	0.23

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [b]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
2-Methylnaphthalene	91-57-6	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
3-Methylchloranthrene	56-49-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	9.7	1.60E-05	1020	8,760	1.52E-07	6.66E-07
Acenaphthene	83-32-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Acenaphthylene	203-96-8	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Anthracene	120-12-7	9.7	2.40E-06	1020	8,760	2.28E-08	1.00E-07
Benz(a)anthracene	56-55-3	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzene	71-43-2	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Benzo(a)pyrene	50-32-8	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(b)fluoranthene	205-99-2	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzo(g,h,i)perylene	191-24-2	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(k)fluoranthene	207-08-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Chrysene	218-01-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Dibenz(a,h)anthracene	53-70-3	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Dichlorobenzene	25321-22-6	9.7	1.20E-03	1020	8,760	1.14E-05	5.00E-05
Fluoranthene	206-44-0	9.7	3.00E-06	1020	8,760	2.85E-08	1.25E-07
Fluorene	86-73-7	9.7	2.80E-06	1020	8,760	2.66E-08	1.17E-07
Formaldehyde	50-00-0	9.7	7.50E-02	1020	8,760	7.13E-04	3.12E-03
Hexane	110-54-3	9.7	1.80E+00	1020	8,760	1.71E-02	0.07
Indeno(1,2,3-cd)pyrene	193-39-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Naphthalene	91-20-3	9.7	6.10E-04	1020	8,760	5.80E-06	2.54E-05
Phenanthrene	85-01-8	9.7	1.70E-05	1020	8,760	1.62E-07	7.08E-07
Pyrene	129-00-0	9.7	5.00E-06	1020	8,760	4.75E-08	2.08E-07
Toluene	108-88-3	9.7	3.40E-03	1020	8,760	3.23E-05	1.42E-04
Arsenic	7440-38-2	9.7	2.00E-04	1020	8,760	1.90E-06	8.33E-06
Beryllium	7440-41-7	9.7	1.20E-05	1020	8,760	1.14E-07	5.00E-07
Cadmium	7440-43-9	9.7	1.10E-03	1020	8,760	1.05E-05	4.58E-05
Chromium	7440-47-3	9.7	1.40E-03	1020	8,760	1.33E-05	5.83E-05
Cobalt	7440-48-4	9.7	8.40E-05	1020	8,760	7.99E-07	3.50E-06
Manganese	7439-96-5	9.7	3.80E-04	1020	8,760	3.61E-06	1.58E-05
Mercury	7439-97-6	9.7	2.60E-04	1020	8,760	2.47E-06	1.08E-05
Nickel	7440-02-0	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Selenium	7782-49-2	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
Total HAPs						0.02	0.08

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Emission Factors from 40 CFR 98 Table C-1

Appendix A: Emission Calculations
Product Stripper Heater

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
		lb/MMscf [a]	lb/MMBtu				
Nitrogen Oxides (NOx)	3.7	100.0	--	1020	8760	0.36	1.59
Carbon Monoxide (CO)	3.7	84.0	--	1020	8760	0.30	1.33
Particulate (PM/PM10/PM2.5)	3.7	7.60	--	1020	8760	0.03	0.12
Sulfur Dioxide (SO2)	3.7	0.60	--	1020	8760	0.00	0.01
Volatile Organic Compounds (VOC)	3.7	5.5	--	1020	8760	0.02	0.09

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [b]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (tons/yr)
2-Methylnaphthalene	91-57-6	3.7	2.40E-05	1020	8760	8.71E-08	3.81E-07
3-Methylchloranthrene	56-49-5	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	3.7	1.60E-05	1020	8760	5.80E-08	2.54E-07
Acenaphthene	83-32-9	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Acenaphthylene	203-96-8	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Anthracene	120-12-7	3.7	2.40E-06	1020	8760	8.71E-09	3.81E-08
Benz(a)anthracene	56-55-3	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Benzene	71-43-2	3.7	2.10E-03	1020	8760	7.62E-06	3.34E-05
Benzo(a)pyrene	50-32-8	3.7	1.20E-06	1020	8760	4.35E-09	1.91E-08
Benzo(b)fluoranthene	205-99-2	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Benzo(g,h,i)perylene	191-24-2	3.7	1.20E-06	1020	8760	4.35E-09	1.91E-08
Benzo(k)fluoranthene	207-08-9	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Chrysene	218-01-9	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Dibenz(a,h)anthracene	53-70-3	3.7	1.20E-06	1020	8760	4.35E-09	1.91E-08
Dichlorobenzene	25321-22-6	3.7	1.20E-03	1020	8760	4.35E-06	1.91E-05
Fluoranthene	206-44-0	3.7	3.00E-06	1020	8760	1.09E-08	4.77E-08
Fluorene	86-73-7	3.7	2.80E-06	1020	8760	1.02E-08	4.45E-08
Formaldehyde	50-00-0	3.7	7.50E-02	1020	8760	2.72E-04	1.19E-03
Hexane	110-54-3	3.7	1.80E+00	1020	8760	6.53E-03	0.03
Indeno(1,2,3-cd)pyrene	193-39-5	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Naphthalene	91-20-3	3.7	6.10E-04	1020	8760	2.21E-06	9.69E-06
Phenanthrene	85-01-8	3.7	1.70E-05	1020	8760	6.17E-08	2.70E-07
Pyrene	129-00-0	3.7	5.00E-06	1020	8760	1.81E-08	7.94E-08
Toluene	108-88-3	3.7	3.40E-03	1020	8760	1.23E-05	5.40E-05
Arsenic	7440-38-2	3.7	2.00E-04	1020	8760	7.25E-07	3.18E-06
Beryllium	7440-41-7	3.7	1.20E-05	1020	8760	4.35E-08	1.91E-07
Cadmium	7440-43-9	3.7	1.10E-03	1020	8760	3.99E-06	1.75E-05
Chromium	7440-47-3	3.7	1.40E-03	1020	8760	5.08E-06	2.22E-05
Cobalt	7440-48-4	3.7	8.40E-05	1020	8760	3.05E-07	1.33E-06
Manganese	7439-96-5	3.7	3.80E-04	1020	8760	1.38E-06	6.04E-06
Mercury	7439-97-6	3.7	2.60E-04	1020	8760	9.43E-07	4.13E-06
Nickel	7440-02-0	3.7	2.10E-03	1020	8760	7.62E-06	3.34E-05
Selenium	7782-49-2	3.7	2.40E-05	1020	8760	8.71E-08	3.81E-07
Total HAPs						0.01	0.03

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Emission Factors from 40 CFR 98 Table C-1

Appendix A: Emission Calculations
VOC Emissions from Storage Tanks

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Storage Liquid	Chemical Profile used in Tanks 4.09d	Shell Height (ft)	Shell Diameter (ft)	Liquid Height (ft)	Average Liquid Height (ft)	Reid Vapor Pressure (psia)	Actual Vapor Pressure (psia)	Temperature (F)	Roof Color	Storage Capacity (gallons)	Tank Type	Liquid Bulk Temperature (° F)	Net Throughput (gallons)	Turnovers	Uncontrolled Annual VOC Emissions (lbs/yr) [a]	Uncontrolled Annual VOC Emissions (tons/yr)
Product Storage Tank (SPK)[b]	Jet Kerosene	40	50	35	16	0.008	0.008	100	white	587,000	Vertical Fixed Roof Tank	100	11,695,408	20	320.76	0.16
Product Storage Tank (SPK)	Jet Kerosene	40	50	35	16	0.008	0.008	100	white	587,000	Vertical Fixed Roof Tank	100	11,695,408	20	320.76	0.16
Product Storage Tank (SPK)	Jet Kerosene	40	50	35	16	0.008	0.008	100	white	587,000	Vertical Fixed Roof Tank	100	11,695,408	20	320.76	0.16
Off-Spec Product Storage Tank (SPK)	Jet Kerosene	30	35	25	16	0.008	0.008	100	white	216,000	Vertical Fixed Roof Tank	100	100,000	0.46	32.34	0.02
Solvent Sump Drum (Amine)[c]	Amine	32	21	18	15	0.02	7.7	100	white	45,000	Vertical Fixed Roof Tank	100	45,000	1	2,016.70	1.01
FT Liquid Storage (HFTL)	Crude Oil	26	22	23	16	0.58	6.7	100	white	73,000	External Floating Roof	300	146,000	2	3,270.87	1.64
FT Liquid Storage (MFTL)	Gasoline RVP7	26	25	23	16	6.59	3.7	100	white	94,300	External Floating Roof	110	188,600	2	14,041.90	7.02
Diesel Storage Tanks (x4) for Emergency Generator and Fire Pump Engine	Distillate Oil 2	11	4	10	6	0.4	0.0056	55	gray/light	4,000	Vertical Fixed Roof Tank	51	6,120	2	1.10	5.49E-04
															Total:	10.16

Notes:
[a] Emissions are calculated using EPA Tanks 4.09d
[b] Assumed SPK as closer to Jet Kerosene while calculating emissions from Tanks 4.09d
[c] Assumed diethylamine as the amine used in the process

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Fire Pump Engine

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	15.3
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	2.8
Engine size (hp)[1]	399
Engine size (kW)[1]	298
Daily hours of operation	4
Annual hours of operation	500
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Engine Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	399	0.2	g/kW-hr	1	0.13	0.03
PM_{10}	-	399	0.2	g/kW-hr	1	0.13	0.03
$PM_{2.5}$ [3]	-	399	0.2	g/kW-hr	1	0.13	0.03
NO_X	-	399	4	g/kW-hr	1	2.62	0.66
CO	630-08-0	399	3.5	g/kW-hr	1	2.30	0.57
SO_2 [4]	7446-09-5	399	0.0015	% S	1	0.0033	8.15E-04
VOC	-	399	0.00247	lb/hp-hr	1	0.99	0.25

Hazardous Air Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	399	3.91E-05	lb/MMBtu	1	1.09E-04	2.73E-05
Acenaphthene	83-32-9	399	1.42E-06	lb/MMBtu	1	3.97E-06	9.92E-07
Acenaphthylene	203-96-8	399	5.06E-06	lb/MMBtu	1	1.41E-05	3.53E-06
Acrolein	107-02-8	399	9.25E-05	lb/MMBtu	1	2.58E-04	6.46E-05
Anthracene	120-12-7	399	1.87E-06	lb/MMBtu	1	5.22E-06	1.31E-06
Benzo(a)anthracene	56-55-3	399	1.68E-06	lb/MMBtu	1	4.69E-06	1.17E-06
Benzene	71-43-2	399	9.33E-04	lb/MMBtu	1	2.61E-03	6.51E-04
Benzo(a)pyrene	50-32-8	399	1.88E-07	lb/MMBtu	1	5.25E-07	1.31E-07
Benzo(b)fluoranthene	205-99-2	399	9.91E-08	lb/MMBtu	1	2.77E-07	6.92E-08
Benzo(g,h,I)perylene	191-24-2	399	4.89E-07	lb/MMBtu	1	1.37E-06	3.41E-07
Benzo(k)fluoranthene	207-08-9	399	1.55E-07	lb/MMBtu	1	4.33E-07	1.08E-07
Chrysene	218-01-9	399	3.53E-07	lb/MMBtu	1	9.86E-07	2.46E-07
Dibenz(a,h)anthracene	53-70-3	399	5.83E-07	lb/MMBtu	1	1.63E-06	4.07E-07
Fluoranthene	206-44-0	399	7.61E-06	lb/MMBtu	1	2.13E-05	5.31E-06
Fluorene	86-73-7	399	2.92E-05	lb/MMBtu	1	8.16E-05	2.04E-05
Formaldehyde	50-00-0	399	1.18E-03	lb/MMBtu	1	3.30E-03	8.24E-04
Indeno(1,2,3-cd)pyrene	193-39-5	399	3.75E-07	lb/MMBtu	1	1.05E-06	2.62E-07
Naphthalene	91-20-3	399	8.48E-05	lb/MMBtu	1	2.37E-04	5.92E-05
Phenanthrene	85-01-8	399	2.94E-05	lb/MMBtu	1	8.21E-05	2.05E-05
Propylene	115-07-1	399	2.58E-03	lb/MMBtu	1	7.21E-03	1.80E-03
Pyrene	129-00-0	399	4.78E-06	lb/MMBtu	1	1.34E-05	3.34E-06
Toluene	108-88-3	399	4.09E-04	lb/MMBtu	1	1.14E-03	2.86E-04
Xylene	1330-20-7	399	2.85E-04	lb/MMBtu	1	7.96E-04	1.99E-04
					Totals:	0.02	3.97E-03

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 4 of 40 CFR 60 Subpart IIII. Other pollutants are based on AP 42, Chapter 3.3, Table 3.3-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

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Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Fire Pump Engine

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	15.3
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	2.8
Engine size (hp)[1]	399
Engine size (kW)[1]	298
Daily hours of operation	4
Annual hours of operation	100
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Engine Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	399	0.2	g/kW-hr	1	0.13	0.01
PM_{10}	-	399	0.2	g/kW-hr	1	0.13	0.01
$PM_{2.5}$ [3]	-	399	0.2	g/kW-hr	1	0.13	0.01
NO_X	-	399	4	g/kW-hr	1	2.62	0.13
CO	630-08-0	399	3.5	g/kW-hr	1	2.30	0.11
SO_2 [4]	7446-09-5	399	0.0015	% S	1	0.0033	1.63E-04
VOC	-	399	0.00247	lb/hp-hr	1	0.99	0.05

Hazardous Air Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	399	3.91E-05	lb/MMBtu	1	1.09E-04	5.46E-06
Acenaphthene	83-32-9	399	1.42E-06	lb/MMBtu	1	3.97E-06	1.98E-07
Acenaphthylene	203-96-8	399	5.06E-06	lb/MMBtu	1	1.41E-05	7.07E-07
Acrolein	107-02-8	399	9.25E-05	lb/MMBtu	1	2.58E-04	1.29E-05
Anthracene	120-12-7	399	1.87E-06	lb/MMBtu	1	5.22E-06	2.61E-07
Benzo(a)anthracene	56-55-3	399	1.68E-06	lb/MMBtu	1	4.69E-06	2.35E-07
Benzene	71-43-2	399	9.33E-04	lb/MMBtu	1	2.61E-03	1.30E-04
Benzo(a)pyrene	50-32-8	399	1.88E-07	lb/MMBtu	1	5.25E-07	2.63E-08
Benzo(b)fluoranthene	205-99-2	399	9.91E-08	lb/MMBtu	1	2.77E-07	1.38E-08
Benzo(g,h,I)perylene	191-24-2	399	4.89E-07	lb/MMBtu	1	1.37E-06	6.83E-08
Benzo(k)fluoranthene	207-08-9	399	1.55E-07	lb/MMBtu	1	4.33E-07	2.16E-08
Chrysene	218-01-9	399	3.53E-07	lb/MMBtu	1	9.86E-07	4.93E-08
Dibenz(a,h)anthracene	53-70-3	399	5.83E-07	lb/MMBtu	1	1.63E-06	8.14E-08
Fluoranthene	206-44-0	399	7.61E-06	lb/MMBtu	1	2.13E-05	1.06E-06
Fluorene	86-73-7	399	2.92E-05	lb/MMBtu	1	8.16E-05	4.08E-06
Formaldehyde	50-00-0	399	1.18E-03	lb/MMBtu	1	3.30E-03	1.65E-04
Indeno(1,2,3-cd)pyrene	193-39-5	399	3.75E-07	lb/MMBtu	1	1.05E-06	5.24E-08
Naphthalene	91-20-3	399	8.48E-05	lb/MMBtu	1	2.37E-04	1.18E-05
Phenanthrene	85-01-8	399	2.94E-05	lb/MMBtu	1	8.21E-05	4.11E-06
Propylene	115-07-1	399	2.58E-03	lb/MMBtu	1	7.21E-03	3.60E-04
Pyrene	129-00-0	399	4.78E-06	lb/MMBtu	1	1.34E-05	6.68E-07
Toluene	108-88-3	399	4.09E-04	lb/MMBtu	1	1.14E-03	5.71E-05
Xylene	1330-20-7	399	2.85E-04	lb/MMBtu	1	7.96E-04	3.98E-05
					Totals:	0.02	7.94E-04

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 4 of 40 CFR 60 Subpart IIII. Other pollutants are based on AP 42, Chapter 3.3, Table 3.3-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

YDS

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Emergency Generator

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	205.6
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	28.2
Engine size (hp)[1]	4029
Engine size (kW)[1]	3004
Daily hours of operation	4
Annual hours of operation	500
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	4029	0.2	g/kW-hr	1	1.32	0.33
PM_{10}	-	4029	0.2	g/kW-hr	1	1.32	0.33
$PM_{2.5}$ [3]	-	4029	0.2	g/kW-hr	1	1.32	0.33
NO_X	-	4029	6.4	g/kW-hr	1	42.39	10.60
CO	630-08-0	4029	3.5	g/kW-hr	1	23.18	5.79
SO_2 [4]	7446-09-5	4029	0.0015	% S	1	0.0438	0.01
VOC	-	4029	7.05E-04	lb/hp-hr	1	2.84	0.71

Hazardous Air Pollutants	CAS	Engine Size (hp)	Emission Factor [5]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	4029	3.91E-05	lb/MMBtu	1	1.10E-03	2.76E-04
Acenaphthene	83-32-9	4029	1.42E-06	lb/MMBtu	1	4.00E-05	1.00E-05
Acenaphthylene	203-96-8	4029	5.06E-06	lb/MMBtu	1	1.43E-04	3.57E-05
Acrolein	107-02-8	4029	9.25E-05	lb/MMBtu	1	2.61E-03	6.52E-04
Anthracene	120-12-7	4029	1.87E-06	lb/MMBtu	1	5.27E-05	1.32E-05
Benzo(a)anthracene	56-55-3	4029	1.68E-06	lb/MMBtu	1	4.74E-05	1.18E-05
Benzene	71-43-2	4029	9.33E-04	lb/MMBtu	1	2.63E-02	6.58E-03
Benzo(a)pyrene	50-32-8	4029	1.88E-07	lb/MMBtu	1	5.30E-06	1.33E-06
Benzo(b)fluoranthene	205-99-2	4029	9.91E-08	lb/MMBtu	1	2.79E-06	6.99E-07
Benzo(g,h,I)perylene	191-24-2	4029	4.89E-07	lb/MMBtu	1	1.38E-05	3.45E-06
Benzo(k)fluoranthene	207-08-9	4029	1.55E-07	lb/MMBtu	1	4.37E-06	1.09E-06
Chrysene	218-01-9	4029	3.53E-07	lb/MMBtu	1	9.95E-06	2.49E-06
Dibenz(a,h)anthracene	53-70-3	4029	5.83E-07	lb/MMBtu	1	1.64E-05	4.11E-06
Fluoranthene	206-44-0	4029	7.61E-06	lb/MMBtu	1	2.15E-04	5.37E-05
Fluorene	86-73-7	4029	2.92E-05	lb/MMBtu	1	8.23E-04	2.06E-04
Formaldehyde	50-00-0	4029	1.18E-03	lb/MMBtu	1	3.33E-02	8.32E-03
Indeno(1,2,3-cd)pyrene	193-39-5	4029	3.75E-07	lb/MMBtu	1	1.06E-05	2.64E-06
Naphthalene	91-20-3	4029	8.48E-05	lb/MMBtu	1	2.39E-03	5.98E-04
Phenanthrene	85-01-8	4029	2.94E-05	lb/MMBtu	1	8.29E-04	2.07E-04
Propylene	115-07-1	4029	2.58E-03	lb/MMBtu	1	7.28E-02	1.82E-02
Pyrene	129-00-0	4029	4.78E-06	lb/MMBtu	1	1.35E-04	3.37E-05
Toluene	108-88-3	4029	4.09E-04	lb/MMBtu	1	1.15E-02	2.88E-03
Xylene	1330-20-7	4029	2.85E-04	lb/MMBtu	1	8.04E-03	2.01E-03
					Totals:	0.16	0.04

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 1 of 40 CFR 89.112. Other pollutants are based on AP 42, Chapter 3.4, Table 3.4-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

YDS

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Emergency Generator

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	205.6
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	28.2
Engine size (hp)[1]	4029
Engine size (kW)[1]	3004
Daily hours of operation	4
Annual hours of operation	100
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	4029	0.2	g/kW-hr	1	1.32	0.07
PM_{10}	-	4029	0.2	g/kW-hr	1	1.32	0.07
$PM_{2.5}$ [3]	-	4029	0.2	g/kW-hr	1	1.32	0.07
NO_X	-	4029	6.4	g/kW-hr	1	42.39	2.12
CO	630-08-0	4029	3.5	g/kW-hr	1	23.18	1.16
SO_2 [4]	7446-09-5	4029	0.0015	% S	1	0.0438	2.19E-03
VOC	-	4029	7.05E-04	lb/hp-hr	1	2.84	0.14

Hazardous Air Pollutants	CAS	Engine Size (hp)	Emission Factor [5]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	4029	3.91E-05	lb/MMBtu	1	1.10E-03	5.51E-05
Acenaphthene	83-32-9	4029	1.42E-06	lb/MMBtu	1	4.00E-05	2.00E-06
Acenaphthylene	203-96-8	4029	5.06E-06	lb/MMBtu	1	1.43E-04	7.13E-06
Acrolein	107-02-8	4029	9.25E-05	lb/MMBtu	1	2.61E-03	1.30E-04
Anthracene	120-12-7	4029	1.87E-06	lb/MMBtu	1	5.27E-05	2.64E-06
Benzo(a)anthracene	56-55-3	4029	1.68E-06	lb/MMBtu	1	4.74E-05	2.37E-06
Benzene	71-43-2	4029	9.33E-04	lb/MMBtu	1	2.63E-02	1.32E-03
Benzo(a)pyrene	50-32-8	4029	1.88E-07	lb/MMBtu	1	5.30E-06	2.65E-07
Benzo(b)fluoranthene	205-99-2	4029	9.91E-08	lb/MMBtu	1	2.79E-06	1.40E-07
Benzo(g,h,I)perylene	191-24-2	4029	4.89E-07	lb/MMBtu	1	1.38E-05	6.89E-07
Benzo(k)fluoranthene	207-08-9	4029	1.55E-07	lb/MMBtu	1	4.37E-06	2.19E-07
Chrysene	218-01-9	4029	3.53E-07	lb/MMBtu	1	9.95E-06	4.98E-07
Dibenz(a,h)anthracene	53-70-3	4029	5.83E-07	lb/MMBtu	1	1.64E-05	8.22E-07
Fluoranthene	206-44-0	4029	7.61E-06	lb/MMBtu	1	2.15E-04	1.07E-05
Fluorene	86-73-7	4029	2.92E-05	lb/MMBtu	1	8.23E-04	4.12E-05
Formaldehyde	50-00-0	4029	1.18E-03	lb/MMBtu	1	3.33E-02	1.66E-03
Indeno(1,2,3-cd)pyrene	193-39-5	4029	3.75E-07	lb/MMBtu	1	1.06E-05	5.29E-07
Naphthalene	91-20-3	4029	8.48E-05	lb/MMBtu	1	2.39E-03	1.20E-04
Phenanthrene	85-01-8	4029	2.94E-05	lb/MMBtu	1	8.29E-04	4.15E-05
Propylene	115-07-1	4029	2.58E-03	lb/MMBtu	1	7.28E-02	3.64E-03
Pyrene	129-00-0	4029	4.78E-06	lb/MMBtu	1	1.35E-04	6.74E-06
Toluene	108-88-3	4029	4.09E-04	lb/MMBtu	1	1.15E-02	5.77E-04
Xylene	1330-20-7	4029	2.85E-04	lb/MMBtu	1	8.04E-03	4.02E-04
					Totals:	0.16	8.02E-03

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 1 of 40 CFR 89.112. Other pollutants are based on AP 42, Chapter 3.4, Table 3.4-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

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Appendix A: Emission Calculations
Cooling Tower

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameter [a]	Units	Value
Cooling tower Circulation Rate	gpm	39,930
Cooling tower Circulation Rate	lb/hr	19,973,785
Total Dissolved Solids	ppm	790
Annual hours of Operation	hours	8760
Drift[c]	%	0.001
PM Emissions	lb/hr	0.1578
PM Emissions	tons/yr	0.6911

Notes:
[a] Data provided by Fulcrum Centerpoint
[b]The TDS assumptions are determined using an estimate of the TDS in incoming process water to the site and three cycles of concentration in the cooling water loop.
[c]The estimate of drift from the cooling tower was taken from the manufacturers' information for high efficiency drift eliminators.
Assume PM=PM10=PM2.5

Appendix A: Emission Calculations
Wastewater Treatment System (WTS)

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

VOC Concentration (mg/L)	Flow (lpm)	VOC Emissions (Mg/yr)	VOC Emissions (tons/yr)
33	1,426	16.89	18.62

Methodology:
VOC Emissions (Mg/yr) = VOC Concentration (mg/L) x Flow (lpm) x 0.000000001 Mg/mg x 60 min/hr x 8,760 hr/yr x f_e
Where:
VOC Concentration = 33 mg/L
Flow = 188,820 lbs/hr = 1,426 lpm
f_e = 0.683 (Weighted Average Value from EPA 453 D-93-056)

Appendix A: Emission Calculations
Truck Loading Loadout Flare (LOAD)

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

1. Flare Stream Emissions

	Molecular Weight, M (lb/lb mole)	Loading Loss, L_L (lb/kgal)	Annual Throughput (kgal/yr)	VOC Input (lb/yr)	Heat Content[1] (MMBtu/lb)	Heat Input (MMBtu/yr)
Synthetic Paraffinic Kerosene (SPK)	130.00	0.025	34,000	848	0.0196	16.60
Total			34,000	848		**16.60**

Notes:
1. Product heat content provided by the source, 8/11/2021.

Methodology
VOC Input (lb/yr) = Loading Loss (lb/kgal) x Annual Throughput (kgal/yr)
Heat Input (MMBtu/yr) = VOC Input (lb/yr) x Heat Content (MMBtu/lb)

A. Criteria Pollutants

	Pollutant						
	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO
Emission Factor[1] (lb/MMBtu)	0.048	0.048	0.048	-[3]	0.068	-[4]	0.31
Potential to Emit (tons/yr)	3.99E-04	3.99E-04	3.99E-04	1.00E-08	5.65E-04		2.57E-03

Notes:
1. NOx and CO emission factors based on Chapter 13.5, AP-42.
2. PM emissions factors based on Fulcrum Centerpoint estimate of soot content of 40 ug/L in a lightly smoking flare.
3. SO2 emissions based on maximum H2S concentration in vent gas and actual vent gas usage. H2S concentration and gas flow of SPK vapor provided by the source.
4. VOC emissions are accounted for in the loading rack PTE.

Methodology
Potential to Emit (tons/yr) = Emission Factor (lb/MMBtu) x Total Heat Input (MMBtu/yr) / 2,000 (lb/ton)
SO2 Potential to Emit (tons/yr) = 0.005 ppm x 2 lb/hr x 1 / 1,000,000

B. Hazardous Air Pollutants

HAP Emissions are accounted for in the loading rack PTE.

Appendix A: Emission Calculations
Truck Loading Loadout Flare (LOAD)

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

2. Flare (LOAD) Pilot Operation

Heat Input Capacity MMBtu/hr	mmBtu / mmscf	Potential Throughput MMCF/yr
0.12	1020	1.0

	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	9.79E-04	3.92E-03	3.92E-03	3.09E-04	0.05	2.83E-03	0.04

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.10E-03	1.20E-03	0.08	1.80	3.40E-03	
Potential Emission in tons/yr	1.08E-06	6.18E-07	3.86E-05	9.28E-04	1.75E-06	**9.70E-04**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.00E-04	1.10E-03	1.40E-03	3.80E-04	2.10E-03	
Potential Emission in tons/yr	2.58E-07	5.67E-07	7.21E-07	1.96E-07	1.08E-06	**2.8E-06**
					Total HAPs	**9.72E-04**
					Worst HAP	**9.28E-04**

Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.

3. Potential to Emit After Issuance

	Pollutant						
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO
Flare Steam (tons/yr)	3.99E-04	3.99E-04	3.99E-04	1.00E-08	5.65E-04	-	2.57E-03
Pilot Operations (tons/yr)	9.79E-04	3.92E-03	3.92E-03	3.09E-04	0.05	2.83E-03	0.04
Total	1.38E-03	4.31E-03	4.31E-03	3.09E-04	0.05	2.83E-03	0.05

Appendix A: Emissions Calculations
Truck & Railcar Loadout System

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

1. VOC

Uncontrolled loading loss from AP-42 Chapter 5.2, Eqn. 1.

L_L = 12.46 (SPM / T)
Where L_L = Loading Loss (lb/kgal)
S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of jet kerosene (Jet A) (see Table 7.1-2) = 0.008 psia
M = molecular weight of jet kerosene (Jet A) vapors (see Table 7.1-2) = 130
T = temperature of bulk liquid loaded, °R (°F + 460)

Fuel Type	Saturation Factor	True Vapor Pressure (psia)	Molecular Weight (lb/lb-mole)	Temperature (°R)	L_L Loading Loss (lb/kgal)	Annual Throughput (kgal/yr)	Uncontrolled VOC PTE (ton/yr)	Emission Control Efficiency (%)	Controlled VOC Emissions (ton/yr)	Emissions Limit (lb/kgal)
Synthetic Paraffinic Kerosene (SPK)	1.0	0.008	130	519.67	0.025	34,000	0.42	98%	0.01	4.99E-04
Total							**0.42**		**0.01**	

Methodology
1 kgal = 1,000 gal
Vapor recovery collection efficiency is from AP-42 Chapter 5.2.
Uncontrolled VOC PTE (ton/yr) = Annual throughput (kgal/yr) x loading loss (lb/kgal) x 1 ton / 2000 lb
Controlled VOC PTE (ton/yr) = Uncontrolled VOC PTE (ton/yr) x [1 - (Control Eff x Collection Eff.)]
Emissions Limit (lb/kgal) = L_L (lb/kgal) x (1-Control Efficiency (%)/100)

2. Hazardous Air Pollutants

HAP	HAP/VOC (wt%)	Uncontrolled PTE (tons/yr)
Benzene	0.9	3.82E-03
Cumene	0.1	4.24E-04
Ethylbenzene	0.1	4.24E-04
n-Hexane	1.6	6.78E-03
Naphthalene	0.5	2.12E-03
Toluene	1.3	5.51E-03
2,2,4-Trimethylpentane	0.8	3.39E-03
Xylenes	0.5	2.12E-03
Total HAPs		0.02

Notes:

Source: Table 3-2 Gasoline HAP Vapor Profile, Technical Guidance-Stage II Vapor Recovery Systems for Control of Vehicle Refueling Emissions at Gasoline Dispensing Facilities, Vol. I: Chapters, EPA 450/3-91-022a, Nov 1991. The HAP profile is used because emissions from truck loading operations are determined by the vapors from the last product transported, motor gasoline as a worst case for this source.

Uncontrolled HAP PTE (tons/yr) = Uncontrolled VOC PTE (tons/yr) * HAP/VOC (wt%)/100

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Paved Roads at Industrial Site
The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight Loaded (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	120.0	1.0	120.0	19.0	2280.0	2000	0.379	45.5	16590.9
Vehicle (leaving plant) (one-way trip)	120.0	1.0	120.0	0.0	0.0	2000	0.379	45.5	16590.9
Vehicle (entering plant) (one-way trip)	14.0	1.0	14.0	0.0	0.0	3500	0.663	9.3	3387.3
Vehicle (leaving plant) (one-way trip)	14.0	1.0	14.0	20.0	280.0	3500	0.663	9.3	3387.3
		Totals	**268.0**		**2,560.0**			**109.5**	**39,956.4**

Average Vehicle Weight Per Trip = 9.6 tons/trip
Average Miles Per Trip = 0.41 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	9.6	9.6	9.6	tons = average vehicle weight (provided by source)
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 125 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	0.869	0.174	0.0427	lb/mile
Mitigated Emission Factor, Eext =	0.795	0.159	0.0390	lb/mile
Dust Control Efficiency =	50%	50%	50%	(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)	Mitigated PTE of PM (After Control) (tons/yr)	Mitigated PTE of PM10 (After Control) (tons/yr)	Mitigated PTE of PM2.5 (After Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	6.59	1.32	0.32	3.30	0.66	0.16
Vehicle (leaving plant) (one-way trip)	6.59	1.32	0.32	3.30	0.66	0.16
Vehicle (entering plant) (one-way trip)	1.35	0.27	0.07	0.67	0.13	0.03
Vehicle (leaving plant) (one-way trip)	1.35	0.27	0.07	0.67	0.13	0.03
Totals	**15.88**	**3.18**	**0.78**	**7.94**	**1.59**	**0.39**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight Loaded (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (Before Control) (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = [Mitigated PTE (Before Control) (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Fugitive Component Leaks

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

	Petroleum Correlation Constants		Streams 21,26,31,41				Stream 45				Streams 51,60,70,80				ALL STREAMS
Type of Component	Correlation Leak Constant	Exponent	Number of Components [a]	VOC Content (ppmv)	TOC Leak Emission (kg/hr) [b]	VOC Leak (tons/yr)	Number of Components [a]	VOC Content (ppmv)	TOC Leak Emission (kg/hr) [b]	VOC Leak (tons/yr)	Number of Components [a]	VOC Content (ppmv)	TOC Leak Emission (kg/hr) [b]	VOC Leak (tons/yr)	TOTAL (tons/yr)
Valves in gas service	2.29E-06	0.746	592	2.72E-07	1.71E-08	4.02E-17	224	50.91	9.62E-03	7.24E-03	710	21,093.65	2.73	7.84	**7.85**
Valves in light liquid service	2.29E-06	0.746	39	2.72E-07	1.13E-09	2.65E-18	20	50.91	8.59E-04	6.46E-04	395	21,093.65	1.52	4.36	**4.36**
Pump seals	5.03E-05	0.610	0	2.72E-07	0.00E+00	0.00E+00	8	50.91	4.42E-03	3.33E-03	25	21,093.65	0.55	1.57	**1.57**
Compressor seals[c]	1.36E-05	0.589	0	2.72E-07	0.00E+00	0.00E+00	0	50.91	0.00E+00	0.00E+00	0	21,093.65	0.00	0.00	**0.00**
Pressure relief valves[c]	1.36E-05	0.589	0	2.72E-07	0.00E+00	0.00E+00	0	50.91	0.00E+00	0.00E+00	0	21,093.65	0.00	0.00	**0.00**
Connectors	1.53E-06	0.735	974	2.72E-07	2.22E-08	5.22E-17	380	50.91	1.04E-02	7.85E-03	780	21,093.65	1.80	5.16	**5.17**
Sampling connectors	1.53E-06	0.735	6	2.72E-07	1.37E-10	3.22E-19	3	50.91	8.25E-05	6.20E-05	17	21,093.65	0.04	0.11	**0.11**
			TOC WT %	0.148%	**STREAM TOTAL**	**9.54E-17**	TOC WT %	0.386%	**STREAM TOTAL**	**1.91E-02**	TOC WT %	18.585%	**STREAM TOTAL**	**19.04**	**19.06**
			VOC WT %	3.60E-13			VOC WT %	0.030%			VOC WT %	5.532%			
			VOC%/TOC%	2.44E-10			VOC%/TOC%	7.80%			VOC%/TOC%	29.76%			
			HOURS	8,760			HOURS	8,760			HOURS	8,760			

Total HAP Concentration - Liquid Stream	2.0%
Total HAP Concentration - Gas Stream	0.005%

Type of Component	Liquid Stream HAPs (tons/yr)	Gas Stream HAPs (tons/yr)	
Valves in gas service	0.0	0.00038	
Valves in light liquid service	0.09	0	
Pump seals	0.03	0	
Compressor seals	0	0	
Pressure relief valves	0	0	
Connectors	0.03	0.0002	Assume 75% of connectors in gas service/25% in liquid service
Sampling connectors	0.00	0.0000	Assume 75% of sampling connectors in gas service/25% in liquid service
Totals (tons/yr)	0.15	0.0006	
Total HAPs (tons/yr) - Liquid and Gas Streams	**0.15**		

Notes:
[a] Number of components based on the process (P&ID) information provided by Fulcrum
[b] Petroleum leak rate/screening value correlations, Table 2-10, EPA Protocol for Equipment Leak Emission Estimates and Table A-4 EPA Correlation Method
[c] Number of compressor seals and pressure relief valves considered as zero since these are vented to flare.

YDS

Indiana Department of Environmental Management
Office of Air Quality

Appendix B - Proposed Changes to Permit

Addendum to the Technical Support Document (ATSD) for a New Source Construction and Federally Enforceable State Operating Permit (FESOP)

Source Background and Description

Source Name:	Fulcrum Centerpoint, LLC
Source Location:	6200 Industrial Highway, Gary, Indiana 46406
County:	Lake (Calumet)
SIC Code:	2999 (Products of Petroleum and Coal, Not Elsewhere Classified)
Operation Permit No.:	F089-44042-00660
Permit Reviewer:	Andrew Belt

Proposed Changes to Permit

The following changes listed below are made to the permit. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text:

(a) The emission unit descriptions for the flare FLA, ash silos, bed media silos, FT Reactor, utility boiler, syncrude upgrading section, and truck and railcar loadout system (TRC) in Sections A.2, D.1, E.1, E.3, and E.4 of the permit are revised to provide clarification.

(b) The permit is revised to include the following new conditions that were inadvertently omitted from the draft permit:

(1) Section C.6 - Fugitive Particulate Matter Emissions [326 IAC 6.8-10-3];

(2) Section C.7 - Lake County Particulate Matter Contingency Measures [326 IAC 6.8-11];

(3) Section C.8 - Stack Height [326 IAC 1-7];

(4) Section C.14 - Emergency Reduction Plans [326 IAC 1-5-2][326 IAC 1-5-3].

All remaining conditions in Section C are renumbered accordingly.

(c) Conditions D.1.1, D.1.2, D.1.6, D.1.10, D.1.21, and the emission unit descriptions are revised to specify that the ash silos and bed media silos are each controlled by a filter (not a baghouse).

(d) Conditions D.1.2(a) and (i) of the permit are revised to provide clarification.

(e) The CO limit in Condition D.1.2(j) of the permit is revised to include the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater and to increase the CO limit to 83.69 tons per twelve (12) consecutive month period.

(f) Condition D.1.3(a) of the permit is revised to define the terms startup and shutdown.

(g) Condition D.1.4 of the permit is revised to refer to all three feedstock storage buildings FDSTG-1, FDSTG-2, and FDSTG-3.

(h) Condition D.1.6(a) of the permit is revised to correct a typographical error.

(i) Conditions D.1.6(g) and D.1.9(a) of the permit is revised to remove the stack testing for NOx emissions from the utility boiler, since Condition D.1.14 of the permit requires a continuous emission monitoring systems (CEMS) for measuring NOx and O2 (or CO2) emissions from the utility boiler SCR system. All remaining items in D.1.6 are renumbered accordingly.

(j) Condition D.1.7 of the permit is revised to cite to the test methods in 326 IAC 8-20-7(6).

(k) Condition D.1.9 of the permit is revised to provide clarification and to include an updated equation for calculating CO emissions.

(l) Condition D.1.10(a) of the permit is revised to refer to the baghouses for each of the three feedstock storage buildings, FDSTG-1, FDSTG-2, and FDSTG-3.

(m) Conditions D.1.10(b) and (c), D.1.11, D.1.12, and D.1.14 are revised to provide clarification.

(n) Condition D.1.15 of the permit is revised to include the requirement to sample and analyze the purge gas stream from the FT Reactor for HAP content once per week and to include instrument calibration requirements.

(o) Conditions D.1.17(b) and (c) of the permit are revised to specify the SCR 3-hour average temperature and the minimum one-hour ammonia injection rate.

(p) Condition D.1.19 and D.1.20 are revised to provide clarification.

(q) The permit is revised to include a new Condition D.1.21 with Bag Leak Detection System (BLDS) requirements for the feedstock storage buildings (FDSTG-1, FDSTG-2, and FDSTG-3), feedstock dryers (DRYER-1, DRYER-2, and DRYER-3), ash silos (ASH1, ASH2, and ASH3), and bed media silos (BMS1, BMS2, and BMS3) and to remove the previous Condition D.1.21 (Visible Emission Notations).

(r) The permit is revised to include a new Condition D.1.23 that requires the Permittee to sample and analyze the exhaust gas stream from the Sulfur Removal Unit (SRU) once per day in order to determine the H_2S content and to include instrument calibration requirements. All subsequent Section D.1 conditions and condition references are renumbered accordingly.

The vendor guaranteed H2S concentration in the SRU exhaust gas (CO2 vent) is 10 ppmv. A H2S concentration value of 20 ppmv is used in the permit as the response step threshold value. The potential to emit (PTE) calculations for the SRU are updated, assuming that the SRU exhaust gas will have a worst case H2S concentration of 20 ppmv (see Appendix A of this ATSD). Based on the updated calculations, the SRU has a PTE of H2S of 10.47 tons/year.

(s) Previous Condition D.1.23 (now D.1.24) is revised to provide clarification, to include new recordkeeping requirements, and to remove the recordkeeping requirements for visible emission notations.

(t) Previous Condition D.1.23 (Reporting Requirements) is moved and renumbered as Condition D.1.26 (Reporting Requirements). All subsequent Section D.1 conditions are renumbered accordingly.

(u) Condition E.1.2 of the permit is revised to include applicable 40 CFR Part 60, Subpart Db, citations that were inadvertently omitted from the draft permit. As specified in the Technical Support Document (TSD) and Condition D.1.14 of the draft permit, a NOx CEMS is required for the utility boiler under the authority of 326 IAC 3-5, 326 IAC 2-8-5(a)(1) and (4), and 40 CFR 60 (NSPS), Subpart Db. Condition E.1.2 is revised to include the citations for the applicable sections under 40 CFR 60.48b that contain NOx CEMS requirements.

(v) The quarterly report forms are revised to provide clarification and to update the CO emissions limit.

(w) The Fugitive Dust Control Plan (included as Attachment A to the operating permit) is revised to include addition requirements and information and to clarify existing requirements.

The permit is revised as follows, with deleted language as ~~strikethrough~~ text and new language as **bold** text:

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-8-3(c)(3)]

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

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:
***

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, **equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr,** and exhausting to stack SV9.
***

(d) Three (3) ash silos, identified as ASH1, ASH2, and ASH3, approved in 2022 for construction, with a maximum loading rate of 1.0 ton/hr, each, using ~~baghouses~~ **filters** for particulate control, and exhausting to stack SV3.

(e) Three (3) bed media silos, identified as BMS1, BMS2, and BMS3, approved in 2022 for construction, with a maximum loading rate of 0.23 tons per hour, using ~~baghouses~~ **filters** for particulate control, and exhausting to stack SV4.
***

(g) One (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, approved in 2022 for construction, converting syngas into FT liquids (syncrude), with a maximum feedstock equivalent capacity of 1,650 tons per day. The FT liquids are thermally separated into a heavy FT liquid stream (HFTL) and a medium FT liquid stream (MFTL). The water generated in the FT process is separated from the MFTL and sent to the wastewater treatment facility. The HFTL and MFTL are sent to the HFTL and MFTL intermediate storage tanks. Unreacted syngas is separated from the MFTL and either recycled back to the FT **R**~~r~~eactor, sent to the POx units for methane reforming or combusted in the utility boiler as purge gas. The HFTL and MFTL hydrocarbon streams are sent from the intermediate storage tanks to the syncrude upgrading section.

(h) One (1) utility boiler, identified as BOIL, approved in 2022 for construction, with a maximum heat input capacity of 249.20 MMBtu/hr for natural gas and 36.80 MMBtu/hr for purge gas, using a SCR for **NOx**~~NOX~~ control and an oxidation catalyst for VOC and CO control, and exhausting to stack SV10**. The utility boiler is equipped with a**

continuous emission monitoring systems (CEMS) for measuring NOx and O_2 (or CO_2) emissions from the SCR system.
***

(k) One (1) syncrude upgrading section, cracking syncrude from the FT synthesis reactor into Synthetic Paraffinic Kerosene (SPK) and **naphtha**~~naptha~~, consisting of the following:
***

(q) One (1) truck and railcar loadout system, identified as TRC, approved in 2022 for construction, with a maximum throughput rate of 34,000,000 gallons of synthetic paraffinic kerosene (SPK) per year, using flare LOAD as control, which is supplemented by natural gas, has a maximum heat input capacity of 16.60 MMBtu/hr, **equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr,** and exhausting through stack SV19.
***

C.6 Fugitive Particulate Matter Emissions [326 IAC 6.8-10-3]

Pursuant to 326 IAC 6.8-10-3 (formerly 326 IAC 6-1-11.1) (Lake County Fugitive Particulate Matter Control Requirements), the particulate matter emissions from source wide activities shall meet the following requirements:

(a) The average instantaneous opacity of fugitive particulate emissions from a paved road shall not exceed ten percent (10%).

(b) The average instantaneous opacity of fugitive particulate emissions from an unpaved road shall not exceed ten percent (10%).

(c) The opacity of fugitive particulate emissions from exposed areas shall not exceed ten percent (10%) on a six (6) minute average.

(d) The opacity of fugitive particulate emissions from continuous transfer of material onto and out of storage piles shall not exceed ten percent (10%) on a three (3) minute average.

(e) The opacity of fugitive particulate emissions from storage piles shall not exceed ten percent (10%) on a six (6) minute average.

(f) There shall be a zero (0) percent frequency of visible emission observations of a material during the inplant transportation of material by truck or rail at any time.

(g) The opacity of fugitive particulate emissions from the inplant transportation of material by front end loaders and skip hoists shall not exceed ten percent (10%).

(h) Material processing facilities shall include the following:

(1) There shall be a zero (0) percent frequency of visible emission observations from a building enclosing all or part of the material processing equipment, except from a vent in the building.

(2) The PM10 emissions from building vents shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(3) The PM10 stack emissions from a material processing facility shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(4) The opacity of fugitive particulate emissions from the material processing facilities, except a crusher at which a capture system is not used, shall not exceed ten percent (10%) opacity.

(5) The opacity of fugitive particulate emissions from a crusher at which a capture system is not used shall not exceed fifteen percent (15%).

(i) The opacity of particulate emissions from dust handling equipment shall not exceed ten percent (10%).

(j) Material transfer limits shall be as follows:

(1) The average instantaneous opacity of fugitive particulate emissions from batch transfer shall not exceed ten percent (10%).

(2) Where adequate wetting of the material for fugitive particulate emissions control is prohibitive to further processing or reuse of the material, the opacity shall not exceed ten percent (10%), three (3) minute average.

(3) Slag and kish handling activities at integrated iron and steel plants shall comply with the following particulate emissions limits:

(A) The opacity of fugitive particulate emissions from transfer from pots and trucks into pits shall not exceed twenty percent (20%) on a six (6) minute average.

(B) The opacity of fugitive particulate emissions from transfer from pits into front end loaders and from transfer from front end loaders into trucks shall comply with the fugitive particulate emission limits in 326 IAC 6.8-10-3(9).

(k) Any facility or operation not specified in 326 IAC 6.8-10-3 shall meet a twenty percent (20%), three (3) minute average opacity standard.

The Permittee shall achieve these limits by controlling fugitive particulate matter emissions according to the Fugitive Dust Control Plan (included as Attachment A to the operating permit).

C.7 Lake County Particulate Matter Contingency Measures [326 IAC 6.8-11]

The Permittee shall comply with the applicable provisions of 326 IAC 6.8-11 (Lake County Particulate Matter Contingency Measures).

C.8 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.

C.**9**~~6~~ Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

***

Testing Requirements [326 IAC 2-8-4(3)]

C.**10**~~7~~ Performance Testing [326 IAC 3-6]

***

Compliance Requirements [326 IAC 2-1.1-11]

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

***

Compliance Monitoring Requirements [326 IAC 2-8-4(1)][326 IAC 2-8-5(a)(1)]

C.**12**~~9~~ Compliance Monitoring [326 IAC 2-8-4(3)][326 IAC 2-8-5(a)(1)]

***

C.**13**~~10~~ Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-8-4(3)][326 IAC 2-8-5(1)]

***

Corrective Actions and Response Steps [326 IAC 2-8-4][326 IAC 2-8-5(a)(1)]

C.14 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.**15**~~11~~ Risk Management Plan [326 IAC 2-8-4] [40 CFR 68]

***

C.**16**~~12~~ Response to Excursions or Exceedances [326 IAC 2-8-4] [326 IAC 2-8-5]

***

C.**17**~~13~~ Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-8-4][326 IAC 2-8-5]

***

Record Keeping and Reporting Requirements [326 IAC 2-8-4(3)]

C.**18**~~14~~ Emission Statement [326 IAC 2-6]

***

C.**19**~~15~~ General Record Keeping Requirements [326 IAC 2-8-4(3)] [326 IAC 2-8-5]

***

C.**20**~~16~~ General Reporting Requirements [326 IAC 2-8-4(3)(C)] [326 IAC 2-1.1-11]

***

Stratospheric Ozone Protection

C.**21**~~17~~ Compliance with 40 CFR 82 and 326 IAC 22-1

***

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:
***

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:
***

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, **equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr,** and exhausting to stack SV9.
***

(d) Three (3) ash silos, identified as ASH1, ASH2, and ASH3, approved in 2022 for construction, with a maximum loading rate of 1.0 ton/hr, each, using ~~baghouses~~ **filters** for particulate control, and exhausting to stack SV3.

(e) Three (3) bed media silos, identified as BMS1, BMS2, and BMS3, approved in 2022 for construction, with a maximum loading rate of 0.23 tons per hour, using ~~baghouses~~ **filters** for particulate control, and exhausting to stack SV4.
***

(g) One (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, approved in 2022 for construction, converting syngas into FT liquids (syncrude), with a maximum feedstock equivalent capacity of 1,650 tons per day. The FT liquids are thermally separated into a heavy FT liquid stream (HFTL) and a medium FT liquid stream (MFTL). The water generated in the FT process is separated from the MFTL and sent to the wastewater treatment facility. The HFTL and MFTL are sent to the HFTL and MFTL intermediate storage tanks. Unreacted syngas is separated from the MFTL and either recycled back to the FT **R**~~r~~eactor, sent to the POx units for methane reforming or combusted in the utility boiler as purge gas. The HFTL and MFTL hydrocarbon streams are sent from the intermediate storage tanks to the syncrude upgrading section.

(h) One (1) utility boiler, identified as BOIL, approved in 2022 for construction, with a maximum heat input capacity of 249.20 MMBtu/hr for natural gas and 36.80 MMBtu/hr for purge gas, using a SCR for **NOx**~~NOX~~ control and an oxidation catalyst for VOC and CO control, and exhausting to stack SV10**. The utility boiler is equipped with a continuous emission monitoring systems (CEMS) for measuring NOx and O_2 (or CO_2) emissions from the SCR system**.
***

(k) One (1) syncrude upgrading section, cracking syncrude from the FT synthesis reactor into Synthetic Paraffinic Kerosene (SPK) and **naphtha**~~naptha~~, consisting of the following:
***

(q) One (1) truck and railcar loadout system, identified as TRC, approved in 2022 for construction, with a maximum throughput rate of 34,000,000 gallons of synthetic paraffinic kerosene (SPK) per year, using flare LOAD as control, which is supplemented by natural gas, has a maximum heat input capacity of 16.60 MMBtu/hr, **equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr,** and exhausting through stack SV19.
***

***

D.1.1 PSD Minor Limits for PM [326 IAC 2-2]

***

Unit Description	Control Device	PM Emission Limit (lbs/hr)
***	***	***
Ash Silo (ASH1)	~~Baghouse~~ **Filter**	0.055
Ash Silo (ASH2)	~~Baghouse~~ **Filter**	0.055
Ash Silo (ASH3)	~~Baghouse~~ **Filter**	0.055
Bed Media Silo (BMS1)	~~Baghouse~~ **Filter**	0.055
Bed Media Silo (BMS2)	~~Baghouse~~ **Filter**	0.055
Bed Media Silo (BMS3)	~~Baghouse~~ **Filter**	0.055

***

D.1.2 FESOP, PSD, and Emission Offset Limits [326 IAC 2-8-4] [326 IAC 2-2] [326 IAC 2-3]

***

(a) PM10 and PM2.5 emissions from the units named in the table below shall not exceed the values shown in the table:

Unit Description	Control Device	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
***	***	***	***
Feedstock Storage Building (FDSTG-3)	Baghouse	2.83	1.42
***	***	***	***
Ash Silo (ASH1)	~~Baghouse~~ **Filter**	0.055	0.055
Ash Silo (ASH2)	~~Baghouse~~ **Filter**	0.055	0.055
Ash Silo (ASH3)	~~Baghouse~~ **Filter**	0.055	0.055
Bed Media Silo (BMS1)	~~Baghouse~~ **Filter**	0.055	0.055
Bed Media Silo (BMS2)	~~Baghouse~~ **Filter**	0.055	0.055
Bed Media Silo (BMS3)	~~Baghouse~~ **Filter**	0.055	0.055

***

(i) Total VOC emissions from FT **R**~~r~~eactor, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks shall not exceed 48.12 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

(j) **Total** CO emissions from the **feedstock dryers, pulse combustors,** utility boiler**, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater** shall not exceed **83.69**~~4.63~~ tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

***

D.1.3 VOC Best Available Control Technology (BACT) [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (VOC BACT), the Permittee shall comply with the following:

(a) The VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor shall be controlled by the utility boiler (BOIL) except when flaring the VOC emissions during startup and shutdown. **The terms startup and shutdown are defined as follows:**

(1) Startup means the setting into operation of the gasifier trains (GT-1, GT-2, and/or GT-3) and/or the FT Reactor, when syngas is being ducted to the flare.

(2) Shutdown means cessation of operation of the gasifier trains (GT-1, GT-2, and/or GT-3) and/or the FT Reactor, when syngas is being ducted to the flare, or the period when gas is being ducted to the flare during draining and inspection of storage tanks.

***

D.1.4 Particulate Emission Limitations for Lake County [326 IAC 6.8-1-2]

(a) Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the **three (3)** ~~one (1)~~ feedstock storage **buildings**, identified as FDSTG**-1, FDSTG-2, and FDSTG-3**, the three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, the three (3) ash silos, identified as ASH1, ASH2, and ASH3, the three (3) bed media silos, identified as BMS1, BMS2, and BMS3, the one (1) evaporative cooling tower, identified as CT, three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, the one (1) loadout flare, identified as LOAD, the one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot (dscf)), each.

***

D.1.6 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a), not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on the feedstock storage **buildings**~~builidngs~~, each controlled by one (1) baghouse, exhausting to stack SV1, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration. PM10 and PM2.5 include filterable and condensable particulate matter.

***

(c) In order to demonstrate compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a) not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on the ash silos, each controlled by one (1) ~~baghouse~~ **filter** exhausting to stack SV3, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration. PM10 and PM2.5 include filterable and condensable particulate matter.

(d) In order to demonstrate compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a) not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on the bed media silos, each controlled by one (1) ~~baghouse~~ **filter** exhausting to stack SV4, utilizing methods as approved by the Commissioner, at least

once every five (5) years from the most recent valid compliance demonstration. PM10 and PM2.5 include filterable and condensable particulate matter.

***

~~(g) In order to demonstrate compliance with Condition D.1.2(h), not later than 180 days after initial start-up, the Permittee shall perform NOx testing on the utility boiler, controlled by a SCR system, exhausting to stack SV10, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.~~

(**g**~~h~~) In order to demonstrate compliance with Condition D.1.2(i), not later than 180 days after initial start-up, the Permittee shall perform VOC (including emission rate and overall control efficiency) testing on the pulse combustors, ~~each controlled by one (1) SCR system,~~ exhausting to stacks SV5, SV6, and SV7, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(**h**~~i~~) In order to demonstrate compliance with Condition D.1.2(i), and D.1.3 not later than 180 days after initial start-up, the Permittee shall perform VOC (including emission rate and overall control efficiency) testing on the utility boiler, controlled by one (1) oxidation catalyst, exhausting to stack SV10, while combusting natural gas and purge gas from the FT Reactor, utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(**i**~~j~~) In order to demonstrate compliance with Condition D.1.2(j) not later than 180 days after initial start-up, the Permittee shall perform CO testing on the utility boiler, controlled by one (1) oxidation catalyst, exhausting to stack SV10 utilizing methods as approved by the Commissioner, at least once every five (5) years from the most recent valid compliance demonstration.

(**j**~~k~~) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.1.7 Volatile Organic Compounds (VOC) - Wastewater

~~Compliance with Condition D.1.2(i), shall be determined by applying one (1) or more of the following test methods and procedures, as appropriate:~~

~~(a) The Permittee shall use one (1) of the following for determining VOC concentration of wastewater samples:~~

~~(1) SW-846 Method 5030B (purge and trap) followed by SW-846 Method 8015B with a DB-5 boiling point (or equivalent column), and flame ionization detector, with the detector calibrated with benzene as required by 40 CFR 261*.~~
~~(2) SW-846 Methods 3810, 5030B (followed by 8021B), 8260B, and 9060 as required by 40 CFR 261*.~~
~~(3) U.S. EPA 40 CFR 136 Methods 602, 624, 1624, 625, 1625*.~~
~~(4) U.S. EPA 40 CFR 63 Method 305*.~~
~~(5) U.S. EPA 40 CFR 60 Method 25D*.~~

~~In the event of any conflict, U.S. EPA 40 CFR 60 Method 25D* takes precedence.~~

~~(b) Flow rate measurements shall be taken at the same time as the concentration measurements.~~

In order to determine compliance with Condition D.1.2(i), the VOC concentration of wastewater samples taken from the wastewater treatment system shall be determined once per week by using one (1) of the test methods specified in 326 IAC 8-20-7(6). Wastewater flow rate measurements shall be taken once per week at the same time as the wastewater VOC concentration measurements.

***

D.1.9 NOx, VOC, and CO Emission Calculations

~~In order to demonstrate compliance~~ **Compliance** with Conditions D.1.2(h), D.1.2(i), and D.1.2(j)~~, the Permittee~~ shall **be determined by calculating** ~~determine~~ the NOx, VOC, and CO emissions for each month using the following equations:

(a) NOx Emissions:
***

Ef_B = 0.0061 lb of NOx per MMBtu ~~or the NOx emission rate determined in the most recent stack test (lb//MMBtu)~~ until the CEMS required by Condition D.1.14 begins operation. Then NOx emissions from the utility boiler shall be determined for the month being reported from the CEMS, lb/month.
F = Flare **(FLA)** Pilot natural gas usage (MMScf/month)
Ef_{FP} = 100 lb of NOx per MMscf
FSUSD = Flare **(FLA)** heat input **from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor** during startup and shutdown (MMBtu/month)
***

(b) VOC Emissions:
***

F = Flare **(FLA)** Pilot natural gas usage (MMScf/month)
Ef_{FP} = 5.5 lb of VOC per MMscf
FSUSD = Flare **(FLA)** heat input **from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor** during startup and shutdown (MMBtu/month)
***

(c) CO Emissions:

$$\cancel{CO\left(\frac{tons}{month}\right) = \frac{B(Ef_B)}{2{,}000\ lbs/ton}}$$

$$\boldsymbol{CO\left(\frac{tons}{month}\right) = \frac{FD(Ef_{FD}) + PC(Ef_{PC}) + B(Ef_B) + F(Ef_{FP}) + FSUSD(Ef_{FSUSD}) + H(Ef_H)}{2{,}000\ lbs/ton}}$$

Where:
FD = Feedstock dryers natural gas heat input (MMBtu/month)
Ef_{FD} = 0.037 lb of CO per MMBtu or the CO emission rate determined in the most recent stack test (lb/MMBtu)
PC = Pulse combustors natural gas heat input (MMBtu/month)
Ef_{PC} = 0.041 lb of CO per MMBtu or the CO emission rate determined in the most recent stack test (lb/MMBtu)
B = Utility boiler combined natural gas and purge gas heat input (MMBtu/month)
Ef_B = 0.0037 lb of CO per MMBtu or the CO emission rate determined in the most recent stack test (lb//MMBtu)
F = Flare (FLA) Pilot natural gas usage (MMScf/month)

Ef_{FP} = 84.0 lb of CO per MMscf
FSUSD = Flare (FLA) heat input from the gasifier trains (GT-1, GT-2, and GT-3) and FT Reactor during startup and shutdown (MMBtu/month)
Ef_{FSUSD} = 0.31 lb of CO per MMBtu
H = Hydrocracker, Fractionator, and Product Stripper combined natural gas usage (MMscf/month)
Ef_{H} = 84.0 lb of CO per MMscf of natural gas

D.1.10 Particulate Control

(a) In order to assure compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a), **each of** the baghouse**s** for particulate control shall be in operation and control emissions from the **respective** feedstock storage buildings **(FDSTG-1, FDSTG-2, and FDSTG-3)** at all times the feedstock storage buildings are in operation.

(b) In order to assure compliance with Conditions D.1.1(a), D.1.2(a), and D.1.4(a), **each of** the baghouses for particulate control shall be in operation and control emissions from the **respective** feedstock dryers **(DRYER-1, DRYER-2, and DRYER-3)** at all times the feedstock dryers are in operation.

(c) In order to assure compliance with Condition D.1.1(a), D.1.2(a), and D.1.4(a), ~~the~~ **each of the** filters for particulate control shall be in operation and control emissions from the **respective** ash silos **(ASH1, ASH2, and ASH3)** and bed media silos **(BMS1, BMS2, and BMS3)** at all times the ash silos and bed media silos are in operation.

***

D.1.11 NOx Control

In order to assure compliance with Condition D.1.2(h), **each of** the selective catalytic reduction (SCR) system**s** for NOx control shall be in operation and control emissions from the **respective** pulse combustors and utility boiler at all times the pulse combustors and utility boiler are in operation.

D.1.12 VOC Control

***

(b) In order to assure compliance with Conditions D.1.2(i), and D.1.3, the utility boiler for **purge gas** VOC control shall be in operation and control emissions from the FT Reactor at all times the FT Reactor is in operation, except during periods of startup and shutdown.

(c) In order to assure compliance with Condition D.1.2(i), the flare (FLA) for VOC control shall be in operation and control emissions from the gasifier trains (GT-1, GT-2, and GT-3) and FT **R**~~r~~eactor during periods of startup and shutdown**.**

***

D.1.14 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5] [326 IAC 2-8-5(a)(1),(4)] [40 CFR 60, Subpart Db]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems **(CEMS)** for the utility boiler shall be calibrated, maintained, and operated for measuring NOx and O_2 (or CO_2) emissions from the SCR system, which meet all applicable performance specifications of 326 IAC 3-5.

***

D.1.15 ~~VOC and~~ HAPs - Purge Gas Sampling **and Analysis**

~~(a) In order to assure compliance with Conditions D.1.2(i) and D.1.3, not later than 180 days after initial start-up, the Permittee shall analyze the purge gas stream from the FT Reactors for the VOC and HAPs content. Testing shall be conducted in accordance with~~

~~the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.~~

~~(b) Not later than ninety (90) after analyzing the purge gas stream, the Permittee shall submit updated VOC and HAP calculations in Appendix A for the FT Reactor, utility boiler, and flare (FLA) to the IDEM OAQ Compliance and Enforcement Branch.~~

(a) The Permittee shall sample and analyze the purge gas stream from the FT Reactor for HAP content once per week.

(b) The instrument used for determining the HAP content shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

***

D.1.17 Selective Catalytic Reduction System Monitoring Requirements - Pulse Combustors

***

(b) Temperature:

(i) A continuous monitoring system shall be calibrated, maintained, and operated on the three (3) selective catalytic reduction systems, used in conjunction with the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3 for measuring operating temperature. From the date of startup until the stack test results are available, the Permittee shall **operate the SCR inlet temperature at or above** ~~determine~~ the 3-hour average temperature **of 550ºF.**~~from the latest valid stack test that demonstrates compliance with limits in Condition D.1.2(h).~~

***

(c) Ammonia injection rate:

(i) A continuous monitoring system shall be calibrated, maintained, and operated on the three (3) selective catalytic reduction systems, used in conjunction with the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3 for measuring the ammonia injection rate. From the date of startup until the stack test results are available, the Permittee shall **maintain an ammonia** ~~determine the~~ injection rate **at or above the one-hour injection rate of 0.26 pounds per hour.**~~from the latest valid stack test that demonstrates compliance with limits in Condition D.1.2(h).~~

***

D.1.19 Catalytic Oxidation System Duct Pressure or Fan Amperage

(a) The Permittee shall determine the appropriate duct pressure or fan amperage from the latest valid stack test that demonstrates compliance with the limit**s** in Conditions D.1.2(i), D.1.2(j), and D.1.3.

***

D.1.20 Flare Pilot Flame

In order to assure compliance with Condition D.1.2(i), the Permittee shall monitor the presence of a flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame when the gasifier trains (GT-1, GT-2, and GT-3) and FT **R**~~r~~eactor are in operation.

~~D.1.21 Visible Emissions Notations~~

~~(a) Daily visible emission notations of the feedstock storage buildings, feedstock dryers, ash silos, and bed media silos stack exhausts (stacks SV1, SV2, SV3, and SV4) shall be performed during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.~~

~~(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, 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 in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit.~~

D.1.21 Bag Leak Detection System (BLDS)

The Permittee shall comply with the following:

(a) The Permittee shall install and operate a continuous bag leak detection system (BLDS) for each of the baghouses controlling the feedstock storage buildings (FDSTG-1, FDSTG-2, and FDSTG-3) and feedstock dryers (DRYER-1, DRYER-2, and DRYER-3), and each of the filters controlling the ash silos (ASH1, ASH2, and ASH3) and bed media silos (BMS1, BMS2, and BMS3).

(b) The BLDS shall meet the following requirements:

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loading.

(3) The bag leak detection system must be equipped with an alarm system that will alarm when an increase in relative particulate loading is detected over a preset level established or verified during a stack test or established according to paragraph (4). The alarm must be located such that it can be heard by the appropriate plant personnel.

(4) The bag leak detection system shall be installed and operated in a manner consistent with available written guidance from the U.S. Environmental Protection Agency or the manufacturer's written specifications and recommendations for installation, operation, and adjustment of the system.

(5) In no event shall the sensitivity be increased by more than 100 percent or decreased by more than 50 percent over a 365 day period unless such adjustment follows a complete baghouse or filter inspection, which demonstrates the baghouse or filter, is in good operating condition.

(6) Failure to take response steps shall be considered a deviation from this permit.

(7) Whenever a BLDS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more during operation of the relevant feedstock storage building (FDSTG-1, FDSTG-2, or FDSTG-3) or feedstock dryer (DRYER-1, DRYER-2, or DRYER-3), ash silos (ASH1, ASH2, and ASH3), and bed media silos (BMS1, BMS2, and BMS3), the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to take visible emission readings from the relevant unit stack.

(A) Visible emission readings of the applicable exhaust stack(s) from the baghouse(s) or filter(s) shall be performed at least once per day during normal daylight operations.

(B) These observations shall be taken in accordance with 40 CFR 60 Appendix A, Method 9 for at least two six (6) minute averages.

(C) If abnormal emissions are observed, the Permittee shall take a reasonable response. Section C.15 – Response to Excursions or Exceedances contains the Permittee's obligations with regard to the reasonable response steps required by this condition. Abnormal emissions are not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

***

D.1.23 SRU - Hydrogen Sulfide (H_2S) Process Gas Sampling and Analysis

(a) The Permittee shall sample and analyze the exhaust gas stream from the Sulfur Removal Unit (SRU) once per day in order to determine the H_2S content. When for any one reading, the H_2S content of the exhaust gas stream from the SRU is greater than 20 ppmv, the Permittee shall take a reasonable response step. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(b) The instrument used for determining the H2S content shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

Record Keeping and Reporting Requirements [326 IAC 2-8-4(3)]

D.1.**24**~~23~~ Record Keeping Requirements

***

(b) To document the compliance status with Conditions D.1.2(h), D.1.2(i), and D.1.2(j), the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (**6**) below shall be taken monthly and shall be complete and sufficient to establish compliance with Conditions D.1.2(h), D.1.2(i), and D.1.2(j).

***

(6) **Calculated** ~~Equivalent~~ NOx, VOC, and CO emissions **for each month and each** ~~since the last compliance~~ determination period.

(c) To document the compliance status of Condition D.1.7, the Permittee shall maintain records of the **weekly wastewater flow rate and VOC concentration from** ~~results of any testing conducted on~~ the wastewater treatment system**.** ~~(relating to approved test methods).~~

(d) To document the compliance status of Condition D.1.15, the Permittee shall maintain records of the **weekly purge gas stream sampling and analysis. The Permittee shall include in its daily record when a sample was not taken and the reason for the lack of a sample (e.g., the process did not operate that day). The Permittee shall include in its daily record when a sample was not analyzed and the reason for the lack of an analysis (e.g., the process did not operate that day).**~~purge gas stream analysis and the VOC and HAP calculations for the FT Reactor, utility boiler, and flare (FLA). Records shall be complete and sufficient to establish compliance with Condition D.1.15.~~

***

~~(i) To document the compliance status with Condition D.1.21, the Permittee shall maintain records of daily visible emission notations of the feedstock storage, feedstock dryers, ash silos, and bed media silos stack exhausts. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).~~

(i) To document the compliance status with Condition D.1.21, the Permittee shall maintain records of the dates and times of all bag leak detection system alarms, the cause of each alarm, and an explanation of all corrective actions taken.

(j) To document the compliance status of Condition D.1.23, the Permittee shall maintain records of the Sulfur Removal Unit (SRU) exhaust gas stream sampling and analysis. The Permittee shall include in its daily record when a sample was not taken and the reason for the lack of a sample (e.g., the process did not operate that day). The Permittee shall include in its daily record when a sample was not analyzed and the reason for the lack of a analysis (e.g., the process did not operate that day).

(**k**~~j~~) Pursuant to 326 IAC 8-9-6(a) and (c), the Permittee shall maintain the following records for the life of the stationary storage vessels and submit a report to IDEM, OAQ containing the following for each vessel:
***

(**l**~~k~~) Pursuant to 326 IAC 8-9-6(h), the owner or operator of each vessel with a design capacity greater than or equal to thirty-nine thousand (39,000) gallons storing a liquid with a maximum true vapor pressure, as measured in accordance with subsection (f), that is normally less than seventy-five hundredths (0.75) psia shall maintain a record and notify the department within thirty (30) days when the maximum true vapor pressure of the liquid exceeds seventy-five hundredths (0.75) psia.

(**m**~~l~~) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

~~D.1.23 Reporting Requirements~~

~~(a) Quarterly summaries of the information to document compliance status with Conditions D.1.2(b), D.1.2(e), D.1.2(h), D.1.2(i), and D.1.2(j) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meet the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).~~

D.1.**25**~~24~~ Record Keeping Requirements for CEMS [326 IAC 2-8-4(3)(A)(iii)] [326 IAC 3-5]

***

(c) To document the compliance status with condition D.1.**16**~~15~~, the Permittee shall record the ammonia flow rate and inlet duct temperature of the SCR at least four (4) times per hour until the primary CEMS or a backup CEMS is brought online. The Permittee shall include in its record, the downtime of the CEMS, reasons of the breakdown, efforts to correct the problem, and when an ammonia flow rate and/or inlet duct temperature reading is not taken during the CEMS downtime and the reason for the lack of a reading (e.g., the process did not operate during that time).

***

D.1.26 Reporting Requirements

Quarterly summaries of the information to document compliance status with Conditions D.1.2(b), D.1.2(e), D.1.2(h), D.1.2(i), and D.1.2(j) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meet the requirements of 326 IAC 2-8-5(a)(1) by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

D.1.**27**~~25~~ Reporting Requirements for CEMS [326 IAC 2-8-4(3)(A)(iii)] [326 IAC 3-5]

***

SECTION E.1 NSPS

Emissions Unit Description:

(h) One (1) utility boiler, identified as BOIL, approved in 2022 for construction, with a maximum heat input capacity of 249.20 MMBtu/hr for natural gas and 36.80 MMBtu/hr for purge gas, using a SCR for **NOx**~~NOX~~ control and an oxidation catalyst for VOC and CO control, and exhausting to stack SV10**. The utility boiler is equipped with a continuous emission monitoring systems (CEMS) for measuring NOx and O_2 (or CO_2) emissions from the SCR system**.

***

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E.1.2 Industrial-Commercial-Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Db]

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(1) 40 CFR 60.40b(a), (g), and (j)
(2) 40 CFR 60.41b
(3) 40 CFR 60.42b(k)(2)
(4) 40 CFR 60.44b(l)(1)**, (h), and (i)**
(5) 40 CFR 60.45b(k)
(**6**~~5~~) 40 CFR 60.46b**(a),** (c), (e), and (f)
(**7**~~6~~) 40 CFR 60.47b(f)
(8) 40 CFR 60.48b(b), (c), (d), (e)(2), (e)(3), (f), (g)
(**9**~~7~~) 40 CFR 60.49b

***

SECTION E.3 NSPS

Emissions Unit Description:

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:
***

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, **equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr,** and exhausting to stack SV9.
***

(q) One (1) truck and railcar loadout system, identified as TRC, approved in 2022 for construction, with a maximum throughput rate of 34,000,000 gallons of synthetic paraffinic kerosene (SPK) per year, using flare LOAD as control, which is supplemented by natural gas, has a maximum heat input capacity of 16.60 MMBtu/hr, **equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr,** and exhausting through stack SV19.
***

***

SECTION E.4 NSPS

Emissions Unit Description:

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:
***

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, **equipped with a natural gas-fired pilot flame with a maximum capacity of 0.12 MMBtu/hr,** and exhausting to stack SV9.
***

***

FESOP Quarterly Report Form:
***

Facility:	Emergency generator
Parameter:	Annual hours of operation
Limit:	**The emergency generator shall** ~~Shall~~ not operate for more than 100 hours per twelve (12) consecutive month period, ~~each,~~ with compliance determined at the end of each month.

***

FESOP Quarterly Report Form:
***

Facility:	Fire pump engine
Parameter:	Annual **hours of** operation
Limit:	**The fire pump engine shall** ~~Shall~~ not operate for more than 100 hours per twelve (12) consecutive month period, ~~each,~~ with compliance determined at the end of each month.

***

FESOP Quarterly Report Form:
***

Facility:	Feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater
Parameter:	Total NOx emissions
Limit:	**Total NOx emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater shall** ~~Shall~~ not exceed 41.91 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

***

FESOP Quarterly Report Form:
***

Facility:	FT **R**~~r~~eactor, feedstock dryer, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks
Parameter:	Total VOC emissions
Limit:	**Total VOC emissions from FT Reactor, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks shall** ~~Shall~~ not exceed 48.12 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

***

FESOP Quarterly Report Form:
***

Facility:	**Feedstock dryers, pulse combustors,** Utility boiler**, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater**
Parameter:	**Total** CO emissions
Limit:	**Total CO emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater** ~~Shall~~ **shall** not exceed ~~4.63~~ **83.69** tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

***

Permit Attachment A: Fugitive Dust Control Plan
***

2.3 Slag Handling Activities

Trivial amounts of potential fugitive dust emissions at Centerpoint are due to the handling of slag, which is collected in either roll-off or hopper bins and later loaded onto trucks and transported to offsite disposal areas. Even when the activities are those of a contractor, Centerpoint is ultimately responsible for the control of these fugitive dust sources on Centerpoint land.

2.**4**~~3~~ Other Fugitive Dust Emissions

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3.1.1 Control of Roadway Fugitive Dust Emissions

Delivery and shipping trucks will be required to adhere to a posted facility speed limit of 20 miles per hour.
***

3.1.2 Control of Fugitive Dust Emissions from Slag Handling Activities

Pursuant to 326 IAC 6.8-10-3(9), fugitive dust emissions generated during slag handling activities will be required to meet a twenty percent (20%), three (3) minute opacity standard. If necessary, the height from which the slag is dropped into the roll-off or hopper bins and the height from which the slag is loaded into trucks shall be limited to meet the twenty percent (20%), three (3) minute opacity standard, under 326 IAC 6.8-10-3(9).

3.1.3~~2~~ Control of Fugitive Dust Emissions from Feedstock Processing and Handling

Feedstock from separately permitted Feedstock Processing Facilities (FPFs) will be delivered to Centerpoint in trucks. After receipt, the Feedstock will be **unloaded and** stored in **one (1) of the** three **(3)** separate Feedstock storage buildings~~.~~**, which are each enclosed with solid walls and doors that will be closed when the facility is not in operation or when feedstock deliveries are not being made.** Each Feedstock storage building will be equipped with a dust collection system.
***

Fugitive Dust Emission Source	Controls	Monitoring Procedure
***	***	***
Slag Handling Activities	**If necessary, the height from which the slag is dropped into the roll-off or hopper bins and the height from which the slag is loaded into trucks shall be limited to meet the twenty percent (20%), three (3) minute opacity standard, under 326 IAC 6.8-10-3(9).**	**Pursuant to 326 IAC 6.8-10-3(9), compliance with this limitation shall be determined by 40 CFR 60, Appendix A, Method 9, except that the opacity standard shall be determined as an average of twelve (12) consecutive observations recorded at fifteen (15) second intervals. Compliance of any operation lasting less than three (3) minutes shall be determined as an average of consecutive observations recorded at fifteen (15) second intervals for the duration of the operation.**
***	***	***

Table 1 - Centerpoint Operation Sources and Controls
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4.2 Monitoring of Slag Handling Activities

If necessary, fugitive dust from slag handling activities shall be controlled to meet the twenty percent (20%), three (3) minute opacity standard, under 326 IAC 6.8-10-3(9) by limiting the height from which the slag is dropped into the roll-off or hopper bins and the height from which the slag is loaded into trucks. Slag handling activities will be visually monitored for opacity emissions and the previously described control methods will be performed as needed.

4.3~~2~~ Monitoring of Other Physical Controls

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IDEM Contact

(a) If you have any questions regarding this permit, please contact Andrew Belt, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-3217 or (800) 451-6027, and ask for Andrew Belt or (317) 232-3217.

(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 Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Indiana Department of Environmental Management
Office of Air Quality

Appendix C - Public Hearing Statements and IDEM Responses

Addendum to the Technical Support Document (ATSD) for a New Source Construction and Federally Enforceable State Operating Permit (FESOP)

Source Background and Description

Source Name:	Fulcrum Centerpoint, LLC
Source Location:	6200 Industrial Highway, Gary, Indiana 46406
County:	Lake (Calumet)
SIC Code:	2999 (Products of Petroleum and Coal, Not Elsewhere Classified)
Operation Permit No.:	F089-44042-00660
Permit Reviewer:	Andrew Belt

On April 27, 2022, IDEM, Office of Air Quality (OAQ) conducted a public hearing regarding the draft New Source Construction and FESOP for Fulcrum Centerpoint, LLC (herein referred to as "Fulcrum" or "Fulcrum Centerpoint").

On May 2, 2022, IDEM, OAQ posted a notice on IDEM's website (https://www.in.gov/idem/public-notices/) informing interested parties that the public notice period was extended an additional 14 days and would end on Monday, May 16, 2022.

IDEM, OAQ thanks all of the commenters and attendees at the public hearing for their interest in the proposed permit and their participation in the permit review process.

This appendix contains the statements/comments made by the public hearing attendees and IDEM's responses. Since many statements/comments were similar and general in nature, IDEM has provided one (1) response for each type of general statement/comment at the beginning of the ATSD under General Statements and IDEM Responses section. Several of IDEM responses in this appendix refer back to the General Statements and IDEM Responses section of the ATSD.

Carolyn McCrady Statements and IDEM Responses

Carolyn McCrady Statements

Good evening, everyone. My name is Carolyn McCrady. I live at 8241 Locust Avenue in Gary, and I'm a member of GARD, Gary Advocates for Responsible Development.

And I am here today because I'm really concerned about Fulcrum's plan to bring, on a daily basis, 120 to 128 diesel trucks into their proposed biorefinery on Gary's westside lakefront location. Those same trucks will then leave the lakefront only to return to the next day refilled with the feedstock they will create and house south of Gary. That is over 200 trucks a day added to the already congested highways and polluted air.

As with the proposed Maya facility on 35th Avenue between Grant and Chase, I'm very upset at the thought of that level of truck traffic, both tailpipe and top-of-the-rig emissions adding to what is already a highly polluted area. Fulcrum acts as if this additional truck traffic will be negligible, and it might -- and it might have been had we been located in another area, like their desert location outside of Reno, Nevada, where only scorpions and rattlesnakes will be affected by whatever emissions the plant has.

But we live here, and they want to locate in a specific area which is a highly industrialized, highly polluted, and is populated both in Gary and East Chicago with some 35,000 people. Of course, because air currents travel, more than those thousands would eventually be affected by this additional pollution, and I'm talking about the truck traffic only here.

I implore your staff at IDEM to look at the cumulative effect of the increased truck traffic, as well as the possibility of a spill, accident or fire in its biorefinery operation. We have heard of such a fire that occurred in May of 2021 at the Brightmark plant in Ashley, Indiana. The plume was so huge that it took several fire departments to eventually bring it under control.

And so, I ask: What would the outcome be here? Don't we need to know whether the Gary Fire Department has had extensive conversations about a possible event, and perhaps the East Chicago Department, too? Will Fulcrum create a fire management team on-site?

Ashley is located in rural area in a town of 930 people. I'm sure that their air and soil and water quality was deeply affected by that fire, because Brightmark is gasifying plastic, which would have disbursed dioxin into the air. To my knowledge, they are still not operational. Furthermore, the public does not know how the fire started, or why. The company has been silent, as has been the Town of Ashley. How is this possible? The scary thing is that Fulcrum claims their feedstock will consist of 30 percent plastic, which they need to combust.

I am hoping that as you examine their air permit, that you take into consideration the whole picture. As you know, Fulcrum has not produced a hazard analysis nor do they have a documentable -- documentable track record of safe operation. In fact, they have no track record of any kind of operation. They are at this point not operating. After having starting their plan in Reno in '07, they are still not operating.

In light of this, it would seem reasonable for IDEM to defer the draft permit decision until the time that Fulcrum has demonstrated with documentation over a significant period of time that it's Sierra Plant near Reno has operated in a safe and environmentally safe manner.

And finally, in order for everyone to have a say beyond May 2nd, and the hearing set for April 27th, which is today, I'm requesting that IDEM extend the 30-day comment period. Our city and everyone on the lakefront, including Chicago, must know for certain that such a tragedy will never happen here as happened in Ashley, Indiana. So much harm has been done to the people and the land and water by industry. When will our health begin to be the first priority? Thank you.

IDEM Response to Carolyn McCrady Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 11 - Incineration
- IDEM Response to General Statement 12 - Public Hearing

With respect to comments about the fire that occurred on May 14, 2021, at the Brightmark Plastics Renewal Indiana 2, LLC, plant in Ashley, Indiana, IDEM, OAQ has no information as to the cause of the fire, the types of material(s) involved in the fire, or the steps takes to put out the

fire. In addition, IDEM, OAQ is not aware of any testing (air, water, or soil) that was done in the area following the fire.

If a permitted (Part 70 or FESOP) source such as Brightmark has a fire that results in a deviation(s) from any air permit requirement(s) or an exceedance of an air permit limitation(s), then that source would be required to report the deviation(s) and any response steps taken as part of a Quarterly Deviation and Compliance Monitoring Report. If a permitted source such as Brightmark has a fire that qualifies as an "emergency" as defined under 326 IAC 2-7-1(12) that lasts one (1) hour or more which results in a exceedance of a permit emission limit, then the source is required to notify IDEM, OAQ by telephone or facsimile within four (4) daytime business hours and submit an Emergency Occurrence Report Form within two (2) working days.

Regarding the comments about dioxin emissions, please see the IDEM Response to George Smolka Statements.

No changes to the draft permit were made as a result of this comment.

Dorreen Carey Statements and IDEM Responses

Dorreen Carey Statements

Good evening, and thank you for the opportunity to speak this evening. My name is Dorreen Carey. I'm a resident of Gary and a member of Gary Advocates for Responsible Development. Thank you to the IDEM for holding this public hearing and providing the opportunity to comment.

First, I would like to state that notwithstanding the preliminary findings of Draft FESOP No. F-089-44042-00660, the trash-to-fuel refinery should never have been considered for permitting and construction at the proposed Gary Buffington Harbor Location on the shoreline of Lake Michigan, surrounded by the Environmental Justice Communities of Gary and East Chicago, Indiana.

With regard to the draft permit, I am requesting on behalf of myself and concerned community members that, due to the complexity of the process and the technical nature of the draft permit, that the public comment period be extended for an additional 30 days.

The Fulcrum trash feedstock gasification process has not yet proven successful. The recently constructed Fulcrum Sierra Plant in the Nevada desert, originally slated to be operating in the fourth quarter of 2021, has pushed that date to the fourth quarter of 2022. I am requesting that the IDEM defer any decision on the draft permit for Fulcrum Centerpoint until the Fulcrum Sierra Plant in the Nevada desert is fully operational, achieves environmental regulatory limits, and produces jet fuel that meets ASTM standards.

The Environmental Justice status of the Gary and East Chicago communities bordering the proposed location of the Fulcrum Centerpoint facility at Buffington Harbor must be taken into account when it's considering permitting a new source of pollution. Historic and current operations of steel mills, refineries, and related industries have overburdened these communities with the result of air, land and water pollution.

I request that prior to any further consideration of the draft FESOP permit, that the IDEM conduct an Environmental Justice screen and impact analysis for neighborhoods within a three-mile radius of the proposed facility. The results of this analysis should be shared with the affected communities through a publicly advertised meeting that provides the opportunity for discussion and feedback. The resulting determination of the Environmental Justice community impact should be included in the permit decision-making process.

How can the IDEM ensure that the municipal garbage proposed for Fulcrum gasification process will provide a consistent feedstock when there is no documentation of where or how the municipal waste will be processed? How can the construction and operation permit be considered without the benefit of this information?

An estimated 200-plus trash feedstock truck trips per day will travel Cline Avenue to and from the proposed Fulcrum Centerpoint plant, increasing diesel tailpipe emissions experienced by neighborhoods fronting Cline Avenue. I request that the IDEM require Fulcrum to factor increased diesel tailpipe emissions resulting from their operations into their emissions inventory, and that these emissions be included in the IDEM assessment of the Environmental Justice impacts.

The Fulcrum Centerpoint location is adjacent to the Indiana Department of Natural Resources Clark & Pine Nature Preserve and Remnant Dune and Swale Wetlands. How will the IDEM and sister agencies ensure that these sensitive natural areas are protected if new industrial construction and operation is added to existing impacts?

The Grand Calumet River and near shore Lake Michigan are listed as Great Lakes areas of concern, and millions have been spent as a result of the IDEM remedial action plan to clean up the river and restore and preserve surrounding natural areas. Permitting construction of new industrial facilities along the shoreline does not support the goal of cleaning up and protecting Lake Michigan. How does the IDEM ensure coordination between the programs and action between their programs and actions to make sure they are not at cross purposes?

The Marquette Plan initiated by former Congressman Peter Visclosky calls for restoring accessible Lake Michigan shoreline to include trails, green space, and other sustainable uses on former remediated industrial properties. Constructing new industrial sources on brownfield properties, where millions have been spent to clean up past pollution does not make environmental or economic sense. Thank you.

IDEM Response to Dorreen Carey Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 12 - Public Hearing

<u>Regarding Comments about Use of Proposed Biorefinery Property</u>

With respect to the comments about the use of the proposed biorefinery property, IDEM, OAQ does not have the authority to take into account the future uses of remediated brownfield properties. These types of evaluations and/or decisions are made by other government bodies, such as the City of Gary Economic Development Commission, the City of Gary Department of Planning & Redevelopment, and/or the City of Gary Zoning Department.

No changes to the draft permit were made as a result of this comment.

Jennifer Rudderham Statements and IDEM Responses

Jennifer Rudderham Statements

Hello. My name is Jennifer Rudderham. I'm also a resident of Gary. I'm partly speaking as a resident and a parent, and also as a member of Gary Advocates for Responsible Development.

I echo the calls for you to extend the comment period 30 days, to allow further analysis and comment from further reaching communities, like Chicago, as has been mentioned, since they share our drinking water. I also call on you guys to defer your decision until we see tangible real-world data coming out of Fulcrum CRM, so we know exactly what we're getting into, and I ask this as a resident of an Environmental Justice Community.

One of my largest concerns is the trucking. We already have multiple trucking industries located in Gary and Northwest Indiana, as well as many trucks that move through our city on a daily basis. The addition of trucks bringing garbage, processed garbage, feedstock, whatever you want to call it, into the city and then back out again just further adds to tire-wear dust, road dust, tailpipe emissions, things that I know your permit generally doesn't look at, but as a member of an Environmental Justice Community, I am requesting that you do take these sort of things into consideration.

Our city does need a more comprehensive and cumulative look at the pollutions that we are faced with, and when companies are coming in, releasing air pollution within their operations, the trucking that comes in needs to be looked at as well, because that does get into our air, that does get into our water, that does get into our soil.

I believe one other person mentioned the request for an Environmental Justice screening to be done in conjunction with this permit process. I, too, echo that, and ask that you report your findings at a community meeting. Thank you for your time.

I'm Jennifer Rudderham again. As I was listening to the comments, there was something that really jumped out to me that has been just like in my mind as I've been listening. Someone mentioned that one of the studies or -- I think you mentioned something about BP being one of the groups that reviewed this process or is promoting this process, and Dr. Julie Peller was talking about plastics and, you know, not knowing what's in this feedstock.

And I know Fulcrum has -- they have acknowledged that at least, what is it, 30 percent of this feedstock is plastic. And so, I'm just connecting the dots in my mind right now, like BP is fossil fuel, plastics are made with fossil fuels, and we need to figure out how to deal with all of this plastic that they've created, and they don't want to be responsible for it.

So, it's no surprise to me that they are funding and creating research that supports the idea of this sort of gasification of plastic garbage, because they're trying to get rid of their problem, and it's just creating a problem for us.

And so, I encourage IDEM -- I don't know what your backgrounds are in understanding gasification or the Fischer-Tropsch -- if I'm pronouncing that correctly -- process. It's -- I understand it's a very complicated process, but I definitely encourage you to look beyond BP-funded studies or explanations of how it works and how it's good for us, because, to me, that's just -- you know, they're writing what they want you to hear, and that's regulatory capturing, and we can't trust them as the source saying that this is good, that this is safe, and that it's okay to bring it to our community. Thank you.

IDEM Response to Jennifer Rudderham Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 4 - Fugitive Dust and Particulate Matter
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 12 - Public Hearing

As discussed in IDEM Response to General Statement 6 (under No Proven Track Record), the proposed biorefinery process (two-step process using steam-reforming gasification and Fischer-Tropsch process) to convert Feedstock into renewable transportation fuel has been proven to work at two (2) gasification facilities operating in North America.

No changes to the draft permit were made as a result of this comment.

Kimmie Gordon Statements and IDEM Responses

Kimmie Gordon Statements

Good afternoon. I'm Kimmie Gordon, Gary Advocates for Responsible Development. I'm the lead organizer for our group, also the founder and director of Brown Faces Green Spaces, does outdoor programming here in Northwest Indiana, and I take groups of families and children and seniors outdoors to enjoy our green spaces across Northwest Indiana, mostly on the west side of Gary, and Ivanhoe South Nature Preserve and in Brunswick Park that are located within that -- that radius of the plant being proposed in Buffington Harbor, for the Fulcrum fuel refinery.

I am in opposition of this refinery personally, because my son suffers respiratory dysfunction because of pollution. We were living seven months -- seven blocks down from the dump when he was born, and the first couple of years of his life, he has developmental delays.

He also has chronic asthma. If I could place a visual in your head right now of what that's like, when an inhaler doesn't work or a nebulizer doesn't work and I'm having to comfort him when he can't breathe, like a fish out of water. You've got a parent that is trying to comfort him and console him on my way to the hospital at 3:00 o'clock in the morning. This happens about -- anywhere from two to three times a year.

We've since moved from that area; however, I am born and raised a native of Brunswick Community, and -- that borders on East Chicago and Hammond. Those communities have been affected for over a hundred years from industrial establishments and pollution, pulmonary diseases, heart disease, asthma, diabetes, stroke, delayed learning, and neurological disorders in children. All are in effect a health hazard of the environmental toxins that we face, you know, on a daily basis.

We leave that area, we come back to that area, and only then do we notice what it smells like, when you're away from that area particularly and you come back and it hits you. But that's what you live in and that's what you breathe every day. You don't know what it smells like. You don't know what clean air smells like, when you leave and you come -- only once you leave and come back. And for the people that

I grew up with and the families and residents and elders that are still in my community, my childhood community there in Brunswick, you know, I have compassion for them.

And I am asking IDEM to delay the air permit until at the very least the Sierra plant in Nevada, out in the desert, which is in fact three times smaller than what they're proposing on the lakefront, our water source, our main water source for millions of people, they're proposing a plant and a process in a facility that has not even been proven yet at their Reno plant out in the desert. It's seven, eight years now.

The plant is not up and running. We have no hazard analysis, nor do they -- are they mandated to give one, and they're not mandated to address our environmental issues or the environmental damage that could possibly take place here in Northwest Indiana. We have been a petri dish and a dumping ground for companies like this far, far, far too long over -- nearly over a hundred years now.

And what we're asking for is better decisions and even higher regulations. If Fulcrum does get permitted to come here, we would like the type of regulations in air permits that happened over in Valparaiso and Munster, not some lower or decreased or laxed regulations where you say, "Oh, it's just Gary. Here, you can pollute this much." Let's take the regulation up a notch, up a few notches. Let's create equity across the board when it comes to regulating air emissions, municipal waste emissions.

So, what we're asking for is fairness, but at the same time, we're asking IDEM to hold off on this permit, which I really think is a reasonable, you know, suggestion, until we see what's going on in Sierra. Without knowing this, the people of Gary and East Chicago are faced with a risk, a greater risk, than would be out at the plant in the desert, because this sits on a lakefront and it's three times larger than what's happening in Reno.

So, we'd like to see what they're doing, the outcome of their process, and if it even works, because several Indiana companies have tried this and they have all failed, and more specifically Brightmark in Ashley, Indiana. Where are they now? They just got dismissed from Macon, Georgia. They made some kind of deal with Macon, Georgia, the Brightmark facility, and Georgia said, "Hmm, you know what? No." So, thank you for hearing, letting me speak. Thank you so much.

IDEM Response to Kimmie Gordon Statements

The proposed permit contains all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board (ERB), which will limit the amount of emissions from the facility to the very lowest level allowed by law. IDEM, OAQ has no authority to create any permit limits or measures that exceed what is legally required for a regulated source. This proposed permit is protective of human health and the environment and will allow for environmentally sound operations that may support a prosperous economy.

All of Indiana's air pollution control rules are contained in Title 326 of the Indiana Administrative Code, which is available at http://www.in.gov/legislative/iac/iac_title?iact=326 on the Internet. The Indiana air permitting requirements that are applicable to this source are part of the state implementation plan (SIP) that is approved by EPA. Environmental laws are enacted by the Indiana legislature and the legislature has delegated rulemaking authority to the Indiana Environmental Rules Board (ERB). For information on how to get involved in Indiana's Environmental Rulemaking Process, please go to https://www.in.gov/idem/legal/rulemaking/ on IDEM's website.

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit

- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

Mary Cossey Statements and IDEM Responses

Mary Cossey Statements

Good evening. My name is Mary Cossey. I'm the Chair of the Communications Committee for the NAACP, Gary Branch. I'm here in place of Lori Latham, who is our Environmental and Climate Justice Committee Chair.

The Gary Branch of the NAACP represents more than 1200 members throughout Northwest Indiana, and we stand in full opposition to Fulcrum's biofuel plant. The NAACP takes seriously its responsibility to protect the communities that we serve from toxic facilities that may emit contaminants to food, water and the lives of the citizens in our community.

What's happening here today in Gary is not a coincidence. We know for a fact that all people are not impacted equally when plants are built that have a negative impact on the environment. The NAACP Environmental Climate Justice Committee has researched and found that race, even more than class, is the number one indicator for the placement of toxic facilities in this country. The research is clear. In the link between where people of color live and where waste facilities choose to locate.

Today we say enough is enough, and we are taking a strong position against IDEM and the oversaturation of cancer-causing plants and permits being approved in Gary, Indiana. We're demanding better oversight of the approval process of permits for Lake and Porter County, more specifically, Gary, Indiana.

Can we afford for IDEM to allow a company like Fulcrum into our community? Should we continue to welcome industries that add to our greenhouse gas emissions? The citizens of Gary deserve the right to have access to its lakefront and experience the same quality of life shared by our surrounding communities. The water that comes from Lake Michigan into our homes every day is very safe and provides the best drinking water in the country.

Today Gary's NAACP is calling for a new vision. Far from burying and burning our waste, we envision the recovering, reusing and recycling of waste and moving toward a zero-waste society; from drilling and burning to harvesting the sun, wind and waves to power our communities; from double-digit unemployment, racist hiring practices and toxic jobs to a workforce that is educated, skilled and trained for jobs in a green economy and making a living wage.

We have the power to do so. Today we are demanding that IDEM defer, then deny Fulcrum's permit to pollute. We are reclaiming this power and standing for our beloved community. As a resident, and all of our residents, we deserve the opportunity, as Michigan City and Whiting, to develop our lakefront to be that of a community that we can enjoy. Thank you.

IDEM Response to Mary Cossey Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit

- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 11 - Incineration

No changes to the draft permit were made as a result of this comment.

Adriane Blaesing Statements and IDEM Responses

Adriane Blaesing Statements

So, my name is Adriane Blaesing, and I'm a resident in Munster, Indiana.

I have a question about the permit that I wanted everyone to hear. The permit states that it's being -- this facility will not be regulated under new source performance standards because it is not burning municipal solid waste; rather, it is burning what is repackaged as -- well, a feedstock. But to me, logic would dictate that unless they have proven how they are going to separate the waste, essentially if they are not doing it as a feedstock, then they could potentially be burning solid waste.

So, the question is: How carefully will they be separating the feedstock? And until that can be guaranteed, the decision about not regulating them under more stringent new source performance standards, I think, should strongly be questioned.

The other question that I wanted everyone to hear is: This is -- the permit as written says that it will not be regulated under the -- as a major source of -- under the National Emissions Standards for Hazardous Air Pollutants, which would be stringent, but I think the catchall is they would be that it would be 25 tons per year of hazardous air pollutants.

But the permit as Fulcrum has written it shows that there would be five tons of hazardous air pollutants and regulated as an area source, which I understand would be less stringent than if they were to be regulated as a major source. How can they determine that or convince IDEM and everyone here that that's the case when they have not actually proven this? And what I would guess is that -- my understanding is that these are calculations, but not actually proven.

I will submit more in the -- in written, but I wanted to ask these in a public forum. Thank you.

IDEM Response to Adriane Blaesing Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 11 - Incineration

No changes to the draft permit were made as a result of this comment.

Lin Kaatz Chary Statements and IDEM Responses

Lin Kaatz Chary Statements

Good afternoon. My name is Lin Kaatz Chary, Dr. Lin Kaatz Chary, and I want to thank you for the opportunity to give my comments to you this afternoon. I am a doctor of public health, with a strong background also in environmental epidemiology. I live in Gary, where I have been a resident for over 40 years, and have spent a great deal of that time working in environmental advocacy, especially around issues of exposure of humans to environmental toxics.

And I come here today to say to you that I in fact think that the IDEM should not permit -- should deny the permit to Fulcrum altogether, and they should deny it on the basis of environmental justice, because even though the DEM has told me many times that environmental justice is a policy, not a regulation, and IDEM is governed by regulations.

And in spite of the fact that two presidents have issued executive orders on environmental justice, nonetheless, the fact that you look at the City of Gary and East Chicago and you see that they are clearly Environmental Justice Communities. They are clearly -- I can do an EJ screen myself on the computer. They are more than qualified in terms of being overburdened historically for decades.

They have more than exceeded the amount of contaminants, that would qualify them as such, and yet they are applying to IDEM and to the State of Indiana for the opportunity to increase that load. They are asking to put more contaminants into our atmosphere, into our air, and through their solid waste permit, into the air, and they're -- DEM doesn't even regulate the emissions from the trucks, which are regulated under a separate -- under separate areas.

And so, essentially, by giving them a permit, you are saying it's okay to increase the pollutant load in an already overburdened community. You are giving them their permission to say, "Okay. Even though this community has historically gotten disproportionate, unfair and unequal contamination, we're going to give you a permit that says you can do more. It's okay with us." Because you're going to go by the letter of the law.

And in effect, and objectively, that makes environmental justice principles meaningless. It says that they mean nothing, because the agencies don't have to make them mean anything. They can just be ignored when companies like Fulcrum, who also don't care about their impact on the communities, they don't -- they say they don't have to do an environmental impact statement, because they haven't received federal money, they have only received 500 million dollars from the State of Indiana, of our money, but that doesn't count. They haven't done a hazard assessment. They haven't dealt with the first responders in case of an accident, and are not required to do so.

I could go on for much longer than five minutes of the deficiencies of this company that are not even covered by the permit, but I will say that I join the previous commenters in asking for an extension of 30 days, because there is a lot more. We need a lot more time. I have looked at this permit, 300 pages, and it would only be fair to give us an opportunity to bring you more information, to look through it more carefully. The citizens do not always have the expertise to look through these permits.

And also I agree with the request to defer your decision on this permit until such time that Fulcrum has demonstrated that they can even make that Sierra plant operational. And just let me point out, if I have another minute. Thank you very much.

Thank you for the opportunity to just add a few comments, and especially in response to the Northwest Indiana Forum statement, but what we have seen together, you know, a lot of the questions that have come up in statements that's very important is how the company which you are -- whose permit you are considering has absolutely shown that there's no transparency in their dealings with the community, and that's been a very important issue.

And I don't know -- I know that they -- I'm assuming that they have a proprietary confidentiality agreement with IDEM and that you must be getting some of this information. I know that they have -- that Brightmark, I've seen their confidentiality proprietary agreement with IDEM, but this is a serious issue. As Dr. Peller pointed out, many of these issues are impossible to know without understanding some of the scientific data that is required that we have no access to.

In addition, we have no access to much of the financial data and a lot of the other things that -- that are important for us to know. So, I would suggest that without that data, how can decisions be made with regard to this permit? And how can citizens have any meaningful participation in this process?

And then I want to talk about the smoke and mirrors that come out of the statement from Northwest Indiana Forum, and a recent editorial that was in the Northwest Indiana Times. And in all of that statement and in all of that editorial, what was really clear is that there was -- in all of the promises and the great things that are going to be brought to us by this company, there was only one short mention of human health, and no mention of the existing burdens that this community already carries, and instead what we're told is all of the benefits that we're going to get, but there's no -- okay. But there's no substance behind it. It's merely circuses.

And I just want to say how can we -- this is a great reflection of where their priorities lie in terms of the community, and how can we be confident that they will meet any of their permit requirements and that they will actually have any of the interests of the community, if and when they come here, when they never ever allude to the community and do anything in advance that shows that the community even factors into their consciences, let alone environmental justice issues?

They're here because they can get a great deal for their location, not because they have any concern for where they are. We might as well be invisible. Thank you so much.

IDEM Response to Lin Kaatz Chary Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 9 - Pollution Control, Compliance Determination/Monitoring, and Stack Testing
- IDEM Response to General Statement 12 - Public Hearing

All information submitted by Fulcrum to IDEM, OAQ about the process and potential emissions is included in the application and associated correspondence that is part of the application. An electronic copy of the permit application and associated correspondence are available via IDEM's Virtual File Cabinet (VFC) for public review or download on the Internet at: https://vfc.idem.in.gov/DocumentSearch.aspx

Regarding the comments about the proposed biorefinery process/technology, please see the IDEM Response to George Smolka Statements.

No changes to the draft permit were made as a result of this comment.

George Smolka Statements and IDEM Responses

George Smolka Statements

My thrust will be primarily both technical and economic. It concerns the technology that they're espousing to use in this, and I think they've done a very poor job overall. With respect to you who are primarily interested in the air quality of the output, of the effluent, in particular, I ask you: Do you know what the maximum temperature will be of the operation? Do you know it? Just "yes" or "no," please. You don't? That's a serious problem.

This system is supposed to follow the guidelines for the use of or the generation of certain materials, mostly hydrocarbons, by the Fischer-Tropsch process, which generally runs from 300 to 572 degrees Fahrenheit, that's 150 to 300 degrees Celsius, if I'm not mistaken.

And the problem within that area is, since you don't know at this point what materials they will be using to generate that heat on the system, it could be generating not only the material that they're interested in, but a lot of other components that are very toxic, among them TCDD or dioxin, which is very toxic. Just to get you an idea of how toxic, which I'm sure both EPA and IDEM know, is three picograms per -- I don't know -- per week or month, for an average individual.

Now, that -- a picogram is very interesting. This is one trillionth of a gram. To put it in terms that most people would be more comfortable with, that's less than a 28th, or close to a 30th, of an ounce, and push that back with nine -- I beg your pardon -- if you're going to the ounce, it would be 11 zeros. So, a decimal point, push it back to 11 zeros, and that is the level at which this stuff is toxic. Considering the lack of information as to the actual process that is involved, I would question that very seriously. We do not need more of that material in our air in this area; okay?

They say the process has been reviewed by BP and some engineers, although they don't tell you what the review found or what the recommendations were. And they mention an engineering firm, but you don't know what kind of engineering firm that is. Theoretically, if they wanted to do this correctly, they would need one that was in chemical engineering, but there's no data on their Web site that indicates that's the kind of engineering firm that they've hired.

The other part of the problem is, as was already mentioned by one of the other speakers, and that is: What are they going to do to ensure that the material that they use to bring the temperature up to the proper levels is safe? My point is: If they are just using ordinary garbage as the source, as the fuel, are they going to make any attempt to remove all salt? Simple problem. How do you get rid of all of the salt from a truckload he garbage. Do you know? No, you don't, and I don't think anybody else knows either. And unfortunately they're not telling us either.

Okay. The other part of the problem is they already say that this is a gas-phased process, so they have to essentially tear apart all of the material, all of the organics that are coming in with the garbage, and convert them into carbon monoxide and hydrogen, and then reform them, reform them through the Fischer-Tropsch process. Well, I'm not sure that that's being done properly.

The other thing is, their pilot operation in Nevada, which is all that I can call it, has anybody done an analysis of the effluent to see how much dioxin is being produced? If they're using raw garbage as the fuel, there has to be some there. Have you checked that? No, you haven't. I don't know if anybody else has. Has the Nevada Environmental Management looked at this or not? I don't know. In any case, I think we need to. As a matter of fact, I would insist that we do.

Does anybody here know who Sasol is? Anybody?

No? All right. They're the largest Fischer-Tropsch operation on the planet -- in the planet. They prepared most of the fuels that were necessary for South Africa during the time that they were under serious sanctions. They are a very big operation, a very wealthy operation, and their technology is extremely good.

Has anybody compared that technology to the technology that's being proposed by Fulcrum? I would probably guess the answer is no. If you don't do that, you're missing the proper procedures. Why? Because Sasol is the most profitable Fischer-Tropsch operation on the face of the planet.

In any case, as you can see, I have a lot of material with me, and if anybody wants to look at it, I have a few things to hand out.

And lastly, most importantly, before I leave, has anyone looked at an alternate operation that could replace Fulcrum in this area? Because I do. I'll give it to you later. Thank you.

All right. I would like to make a closing statement, with respect to what has already been presented here, plus my comments. I think the economic viability of what this Fulcrum organization wants to do is simply not economically viable.

Secondly, the potential pollution damage that they will do, which has certainly not been explained adequately, should put them in a position where you should, in my opinion, deny their permit, and until more information is available on their Nevada operation, no further permitting should be allowed. Thank you.

IDEM Response to George Smolka Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 10 - Feedstock Materials

<u>Regarding the Biorefinery Process Temperature, SASOL Technology, Process Review?</u>

In its air permit application, Fulcrum Centerpoint provided information regarding the proposed biorefinery plant (description of process, emission factors and emission calculation methodology used to determine the potential to emit (PTE) of the proposed facility, state and federal rule applicability, and all additional information provided as part of the permit application) and certified (signed by the responsible official) that the information was truthful, accurate, and complete. IDEM, OAQ reviewed all information provided by Fulcrum Centerpoint in its permit application, requested additional information and/or clarification when necessary, and determined that the information was sufficiently adequate for determining the potential to emit (PTE) of the proposed facility and the applicability of state and federal air rules and air regulations.

With respect to the temperatures of the gasification and Fischer-Tropsch (FT) processes, this information was not necessary for IDEM to formulate emissions limitations for the air permit. As explained in the air permit application, the heat for the gasification process will use a steam reformer that is indirectly heated using natural gas and a small quantity of oxygen will be injected into the reformer to provide any required heat above the output of the indirect heaters. The FT reactions are exothermic, and steam is generated in the FT Reactor to maintain the FT Reactor temperature. Again, it is not necessary for IDEM to know the process temperatures and how they

are achieved and maintained in order to develop the appropriate emission limitations for the air permit.

IDEM, OAQ has no authority to require Fulcrum to submit additional information that exceeds what is legally required for a permit application.

As discussed in IDEM Response to General Statement 6 (under No Proven Track Record), the proposed biorefinery process (two-step process using steam-reforming gasification and Fischer-Tropsch process) to convert Feedstock into renewable transportation fuel has been proven to work at two (2) gasification facilities operating in North America.

The proposed biorefinery will “break down” and convert the Feedstock materials into diesel or jet fuel using a two-step thermochemical process of steam-reforming gasification in an oxygen-deficient atmosphere (producing syngas) and Fischer-Tropsch (FT) synthesis (producing "syncrude" FT liquids that are further upgraded and refined to diesel or jet fuel). The gasification process will not burn, combust, or incinerate the Feedstock materials (i.e., no direct flame will be applied to the Feedstock materials in the gasifier, nor will a flame be propagated as a result of the heating). The proposed gasification and the downstream processes will be fully contained. Prior to conversion to diesel or jet fuel, the syngas will go through a multistep clean-up process to remove contaminants such as sulfur, chlorine, and metals, which will be contained, captured, handled, and treated for disposal.

<u>Regarding Feedstock Materials, the Proposed Biorefinery Gasification Process, and Dioxin Emissions</u>

For the proposed biorefinery, Fulcrum Centerpoint will use a Feedstock material derived from municipal solid waste (MSW) that will be produced at separately permitted Feedstock Processing Facilities (FPFs). The FPFs will use commercially proven processing equipment to shred and sort MSW with sequential steps recovering valuable recyclable materials, removing unwanted components of the waste stream, and improving the physical and compositional attributes of the Feedstock. The Feedstock will consist primarily of mixed paper and cardboard, soft plastic, wood, and textiles, with small amounts of food/yard waste (organic material), non-ferrous metals (e.g., aluminum), ferrous metals, inerts, and fines. During the proposed gasification process, the syngas will go through a multistep clean-up process to remove contaminants such as sulfur, chlorine, and metals, which will be contained, captured, handled, and treated for disposal.

The Feedstock material to be used in the proposed biorefinery will not be raw (unprocessed) garbage and the Feedstock salt content is expected to be low to minimal.

The proposed gasification process is not expected to emit dioxin emissions, since the conditions within the gasifier will not be conducive to dioxin formation. The oxygen-deficient atmosphere (which also prevents combustion of the feedstock material) and higher temperature in the gasifier will not provide the conditions needed for dioxin formation.

<u>Regarding Evaluating Alternate Operation(s) that Could Replace Fulcrum</u>

With respect to evaluating alternate operation(s) that could replace Fulcrum in this area, IDEM, OAQ does not have the authority to evaluate alternate operation(s). These types of evaluations and/or decisions are made by other government bodies, such as the City of Gary Economic Development Commission, the City of Gary Department of Planning & Redevelopment, the City of Gary Zoning Department, or the Indiana Economic Development Corporation.

No changes to the draft permit were made as a result of this comment.

Michael Santos Statements and IDEM Responses

Michael Santos Statements

My name is Michael Santos. I'm speaking today on behalf of Just Transition Northwest Indiana, a grassroots environmental justice organization in the region. We oppose this unproven, risky industry being allowed to operate in Buffington Harbor on the shores of Lake Michigan in Gary, Indiana, a city already so overburdened by accumulative industry pollution that it boggles the mind.

According to the report by the Hoosier Environmental Council entitled "Assessment of Environmental Needs in Northern Lake County," Gary has at least 52 Superfund sites, 423 hazardous waste sites, and more than 460 underground storage tanks.

Gary has some of the worst air quality in the nation due to toxic releases from existing polluting facilities, and the country's eighth highest rate of cancer. EPA also estimates Gary children are exposed to airborne toxins, metals, industrial byproducts, and volatile organic compounds at a rate far higher than those outside this region.

We are staunchly opposed to greenwash false solutions like Fulcrum and taking gambles that would jeopardize the health of Gary residents. After years of delays, Fulcrum's only other plant in Reno, Nevada has yet to be operational and produce its first batch of fuel. Therefore, this technology is absolutely not proven. We implore IDEM to heed the cautionary principle and forego issuing this air permit.

We further request you extend the public comment period for this permit by 30 days, so the entire community can weigh in. The Environmental Justice Community of Gary deserves the chance to thrive and rise above being treating as a sacrifice zone, a place where people's health are sacrificed for the benefit of polluting industries or more affluent, often-white communities.

IDEM must move forward to oppose this permit, to safeguard Gary's health, economy, environment, and the entire region. Please do your dual diligence and deny this permit. Thank you for your consideration.

IDEM Response to Michael Santos Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 12 - Public Hearing

No changes to the draft permit were made as a result of this comment.

Kay Nelson Statements and IDEM Responses

Kay Nelson Statements

Good evening. My name is Kay Nelson. I'm Director of Environmental Affairs for the Northwest Indiana Forum, a regional economic development organization.

Thank you very much for this opportunity to speak in support of the air permit for the Fulcrum Centerpoint biofuels facility.

The Forum recognizes the critical nature of environmental protection that is -- plays out in the environmental economic development process. IDEM's issuance of technically, scientifically and legally sound environmental permits such as the Fulcrum Centerpoint permit issued by the Office of Air for the protection of the residents and the environment.

In choosing Gary's Buffington Harbor Industrial Zone as the site for the Fulcrum Centerpoint, the company will be using four more industrial sites centrally located, with a strong transportation network and existing infrastructure. This brownfield success story for the city and our region is one of importance.

Once the site returns to a taxable property, Fulcrum Centerpoint will provide new tax revenue for the city and generate good-paying jobs. Fulcrum is partnering with the city, Ivy Tech and other stakeholders to create local training and workforce development opportunities to ensure their skilled labor workforce.

In addition to supporting a skilled workforce development in the community, Fulcrum is collaborating with the city in order to determine opportunities that will support green projects and improve Gary's blighted areas. Green projects currently being considered focus on improving quality of life, trails, environmental education, and the protection and/or expansion of green spaces.

Companies like Fulcrum are leading the charge to provide innovative solution for the critical environmental issue with regards to reducing carbon emissions. Within this development process, municipal solid waste will be transformed into a feedstock for a proprietary process platform that will eventually generate aviation biofuel. Redirecting approximately 700,000 tons per year from landfills to generate up to 33 million gallons per year of low-carbon biofuel will result in an 80-percent reduction in greenhouse gases being released.

Given the long history of progress in our region, from the first flight of Octave Chanute at the Indiana Dunes to the upcoming production of a sustainable aviation biofuel that will protect our atmosphere, Fulcrum Centerpoint biofuels is a sustainable project for Gary and the region. Fulcrum Centerpoint will add to our rich history of innovation and will position Gary as a leader for green energy opportunities in the region. This innovative sustainable technology will be replicated across the United States.

Again, the Forum supports the issuance of the IDEM permit, and thank you for this opportunity to speak.

IDEM Response to Kay Nelson Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit

No changes to the draft permit were made as a result of this comment.

Bridgette Murray Statements and IDEM Responses

Bridgette Murray Statements

Hi. My name is Bridgette Murray. I'm a resident of Gary. I was born here, I went to IUN and got my degree, and I moved back here about four years ago. While not planned, I am happy to speak following Kay from Northwest Indiana Forum, but I am definitely speaking against Fulcrum, as most of us here are tonight.

While she was correct in saying that IDEM is technically and legally permitting Fulcrum, that is true, but the air permit only regulates NAAQS, only the National Ambient Air Qualify Standard toxins. There are more -- those are criteria pollutants. We should be more concerned with the over 100 different air toxics that Fulcrum is likely to be putting into our air that are basically unregulated. This is of great concern to myself and to everyone here.

Now, IDEM may be able to extend the comment period, as some people have, but it is highly -- some people have said, but it is highly unlikely that they are going to stop this permit. It's just not going to happen. They -- there are laws and regulations that they have to abide by, and as long as Fulcrum toes the line with their documentation, then they're going to issue the permit, and they legally have to do so.

So, it is up to us to do this locally, to give as much opposition as possible to our city officials, which, as Northwest Indiana Forum has said, are cooperating fully with Fulcrum, because they might give us a hundred jobs that pay decently, but we have to show as much opposition as possible on the local level, to our city and our county, because ultimately, IDEM is not going to come save us.

This permit is probably going to be issued, and we have to, on a local level, oppose this with every fiber in our being that we have for ourselves and for the children that live here in the Gary area that have long been subjected to pollution and no justice from an environmental standpoint.

Thank you for the opportunity to speak.

IDEM Response to Bridgette Murray Statements

IDEM, OAQ issues air pollution permits to facilities that emit regulated levels of regulated air pollutants. If a source emits regulated levels of one or more of the following regulated air pollutants, it may need some type of air permit or approval from IDEM's Office of Air Quality.

- Criteria air pollutants that are regulated under the National Ambient Air Quality Standards (NAAQS). These pollutants include carbon monoxide (CO), lead (Pb), nitrogen dioxide (NOx), ground-level ozone (regulated through its precursors, volatile organic compounds (VOC) and NOx), particulate matter with an aerodynamic diameter less than 10 micrometers (PM10), particulate matter with an aerodynamic diameter less than 2.5 micrometers (PM2.5), and sulfur dioxide (SO_2).
- Hazardous air pollutants (HAPs) regulated under National Emission Standards for Hazardous Air Pollutants (NESHAPs) (sometimes referred to as "toxic air pollutants").
- Pollutants regulated under New Source Performance Standards (NSPS) including dioxins/furan, fluorides, hydrogen chloride, hydrogen sulfide, sulfuric acid mist, total reduced sulfur, reduced sulfur compounds, total suspended particles, total organic compounds, and asbestos.
- Stratospheric ozone depleting substances, including chlorofluorocarbons (CFCs) and other substances, subject to standards promulgated under or established by Title VI of the Clean Air Act (CAA).

The potential to emit (PTE) of all regulated air pollutants for the Fulcrum Centerpoint source was summarized in the Technical Support Document (TSD) for the draft permit and the PTE calculations were included in Appendix A of TSD. This proposed source has the potential to emit PM, PM10, PM2.5, SO2, NOx, VOC, CO, H2S, and several HAPs.

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns

- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 12 - Public Hearing

No changes to the draft permit were made as a result of this comment.

LaTasha Hall Statements and IDEM Responses

LaTasha Hall Statements

Hello. My name is LaTasha Hall. I am a resident, a concerned citizen, from the west side of Gary. I grew up on the west side of Gary. My parents have been on the same street for -- I'm 50, so over 50 years.

I'm here in regards to the company, Fulcrum, being placed in the City of Gary. The issue was brought to the west side community by Timothy Gordon, who continues to remain passionate and concerned about the well being of the citizens of Gary, having a breathable atmosphere.

As a concerned citizen, I would like to say that I would like to see actions that would promote continued sustainable growth in our city. We need companies that will enhance our lives, growth, environment, and housing options. Gary's a prime area, located close to the City of Chicago. We have many highway options to access many cities surrounding us. Instead of trying to make our city an industrial eyesore, it should be made into the thriving city it is meant to be.

We're currently -- Gary is 33 minutes from Chicago; Merrillville, 47 minutes; Hammond, 31 minutes; Crown Point, 53 minutes; Valparaiso, an hour and two minutes; Portage, 44 minutes; and Schererville, 44 minutes. We are so close to this major city that we easily can become a suburb, if families choose to stay here, due to our proximity to Chicago. We are a diamond in the rough and should be treated as such.

What I'm concerned is, is my father worked for -- at the time it was Inland Steel, and he was diagnosed with black lungs, along with many more people. I can remember the stories that he used to tell me. He would come home, he would have on that green suit, it would be covered in soot. He would talk about how the soot was in his nose, and if he blows his nose, the black stuff comes out of his nose. This is type of things that we are experiencing as citizens in this city.

We also -- I agree with a lot of people that were up here, and I don't want to be repetitive, but my concern is I was shown a graph from the EPA, I believe. We're like the highest toxins in the nation in the State of Indiana, not just -- and why we're still here allowing companies to find their homes here when we're already toxic, I don't understand.

And, you know, I'm not abreast of the issues, I'm a dummy to this issue, with lack of knowledge, but I do read information, and she has been providing me with a lot of information, and that information can be intimidating to citizens, because it's a lot of -- it's a lot of data, and if you don't understand it or know about it, you're just going to toss it to the side. So, it's very hard to get the information to our citizens and for them to be comfortable in coming out and speaking about it.

Let's see. Environment -- I didn't even know we had an environmental -- a right to environmental justice. I didn't know there was a such thing. So, if I have a right to breathe fresh air, then I would love to have that. In regards to diabetes, my father died of that as well, black lungs, diabetes. And he's not the only one. They were in a lawsuit for years. Once they pass, it's over with. There are so many companies that are getting away with the toxicities they are placing in the urban areas because they feel we don't care. It's not that we don't care. We're not ready to step up yet. But hopefully that'll happen real soon.

But again, the stories of him coming home. My mom wouldn't even allow him to come home in his work clothes because they were so filthy and contaminated. And then I had cousins that lived in Kentucky, and when they would come down 65, I was young, and they would tell me, "You all's city's got this big cloud over it."

But -- and I'm like, "What are you all even talking about?"

"There's a black cloud over the city." That's what they used to say. And, of course, I'm offended, because I live here. So, I didn't know what they were talking about. But as the years go by, I understood now that it was toxic clouds of dust that were affecting the citizens of Gary.

Now, again, somebody said in a nice way that you don't have expertise to understand the permits. It's true. You have to read the literature. There are terms you don't understand, so you're not comfortable in speaking about something that you don't understand.

But to allow this company to come in, they haven't proven themselves, they have a company that hasn't opened yet, but yet you're trusting that they're going to be glorified with all of these jobs and whatnot, but I don't -- that's a what-if, it's not a positive thing. And we want to breathe, we want our kids to be able to go outside and play and breathe fresh air.

So, what I'm tired of is getting politicians that do not see the potential in Gary. It's a gold mine. It's right there. And I'm on the edge of the west side, so I'm right next to Cline Avenue, right next to the west side, so where you're trying to place it, people are there.

You guys really need to consider the things you're placing in the City of Gary. We want jobs, we want housing, we want to -- we want a better life, we want to be a suburb like Munster and -- I can't say Hammond, because -- I can say Hammond, but I'm thinking about the -- you know, more of the show that they've got going for their city. So, that's what I'm trying to say. Thank you so much for allowing me to speak.

IDEM Response to LaTasha Hall Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

Julie Peller Statements and IDEM Responses

Julie Peller Statements

I come here with concerns for my fellow community members that you're hearing from who are facing the possibility of another polluting industry in their city. I speak on behalf of the Northern Lake County Environmental Partnership. We are a team of scientists concerned about the overburden of hazardous exposures to the residents in the area.

I'm an environmental chemist and a professor of chemistry at Valparaiso University. I collaborate with chemists who work for the Department of Energy. I hold a visiting scientist position at the Notre Dame Radiation Laboratory, which is a Department of Energy facility.

We're here as a consequence of our throwaway society. We make too much garbage, our landfills are filling too fast, and we need to find ways to deal with our trash. We observe large amounts in the environment, and most -- much of the garbage is inundated with toxic chemicals.

These are the kind of problems that the science and engineering community take on. In my own work, I am part of the science community researching the problem and pursuing the best methods to handle waste, those that are safe for environmental and human health and cost effective.

This is municipal solid waste, and we're working on finding ways of separating out the different components. In any chemical process, the feedstock or the reactants matter. Most biotechnology for fuel, these processes are in the research and development stage, and recognizing the immense challenge of working with municipal solid waste, what goes into a chemical conversion system fully depends on the variant reactants, in this case, the feedstocks.

And municipal solid waste consists of nearly everything. From the Department of Energy Web site, the following are looked upon as the most potential feedstocks, and these are complex mixtures. Food waste is one, biosludge and biosolids from wastewater treatment plants, animal waste, specific industrial wastes, for example, from food and beverage manufacturing.

So, in the IDEM notice for public comment, it says, quote, feedstocks from biorefinery will be produced off-site at separate facilities from municipal solid waste, the stuff that we're doing research on. What exactly do you mean by feedstock produced from municipal solid waste? Because it's an incredibly complex mixture.

It's later quoted as -- mentioned as processed engineered feedstock. Again, in the world of chemistry, that's not very well characterized. How much is clarified about these materials in the feedstock? What we know is municipal solid waste is variable, and it makes understanding the outcome of any sort of chemical process much more challenging. How's it possible to set air emission limits on feedstock that is an immense mixture and is highly variable?

I agree with a lot of the comments so far that say Fulcrum has this plant in Nevada. We should wait to see how well this process works, get several months of emissions data for an accurate analysis of air emissions. That should be required as part of the application.

As another concerned citizen noticed -- or noted, the documents say that the facility will employ gasification, a Fischer-Tropsch liquid renewable transportation fuel process, production process. And it says the project will not incinerate or combust municipal solid waste; rather, it will convert feedstock into low-carbon renewable transportation fuel. Gasification is similar to incineration or paralysis in that it is a thermal chemical process, which simply means it requires high temperatures.

For gasification to produce syngas, which is mostly hydrogen and carbon monoxide and other products, extremely high temperatures are required to break all of these chemical bonds of the carbon-based feedstock chemicals. The parameters that are using the gasification process are absolutely dependent upon the feedstock composition, which in the case of municipal solid waste, as we mentioned, constantly varies. It's not well characterized.

I happened to notice that the demonstration plant at an Army base in California recently, on its Web site, said it's using oxygen and steam to heat waste to 4,000 degrees Fahrenheit, or 2200 degrees Celsius. It also indicates that it must dilute the municipal solid waste with pure feedstocks. Other studies cite temperatures ranging from 750 to 1300 degrees Celsius.

If the company wants to claim that they are sustainable or green, why was Gary identified as a place to haul massive amounts of waste, mainly from Illinois, while the proposed sorting facility is many miles from the gasification plant? This is an enormous amount of trucks, transportation, and a very high carbon footprint scenario.

I just also request maybe that we have an extension for these public comments. Thank you very much.

IDEM Response to Julie Peller Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 10 - Feedstock Materials
- IDEM Response to General Statement 11 - Incineration
- IDEM Response to General Statement 12 - Public Hearing

Fulcrum has conducted several waste characterizations in the Greater Chicago area to determine the expected Feedstock material composition. The Feedstock will consist primarily of mixed paper and cardboard, soft plastic, wood, and textiles, with small amounts of food/yard waste (organic material), non-ferrous metals (e.g., aluminum), ferrous metals, inerts, and fines. During the proposed gasification process, the syngas will go through a multistep clean-up process to remove contaminants such as sulfur, chlorine, and metals, which will be contained, captured, handled, and treated for disposal.

The proposed air permit contains emission limitations on PM, PM10, PM2.5, NOx, VOC, and CO with corresponding initial and 5-year repeat stack testing for these air pollutants. The proposed air permit also contains applicable control device operating requirements, monitoring requirements, and associated record keeping and reporting requirements to assure that all permit limitations are enforceable as a practical matter and to assure that the source can demonstrate compliance with all applicable state and federal rules on a continuous basis.

No changes to the draft permit were made as a result of this comment.

Rep. Ragen Hatcher Statements and IDEM Responses

Rep. Ragen Hatcher Statements

Good evening. I'm Ragen Hatcher, State Representative, District 3, and I'd like to call on State Senator Eddie Melton to join me, so we can kind of give all of our comments all at once.

As a general statement for the Indiana delegation, legislative delegation, that includes State Representative Earl Harris, Vernon Smith, State Senator Lonnie Randolph, myself, and State Senator Eddie Melton, we are against any additional industry in Northwest Indiana that impacts air or water quality.

In addition to that, we have a letter that will be going to IDEM. I'm just going to read the highlighted section of it. Fulcrum intends to develop a biorefinery in the area to convert municipal solid waste to jet

fuel. From our understanding, the proposed refinement process is relatively untested, and the only similar plant is operating in a remote area in Nevada. Constituents have reached out to our offices with concerns about both the capability of the proposed refinery and the environmental impacts.

My constituents are additionally concerned about the increased road traffic and diesel emissions that will be associated with this facility. We request that the emission levels be included in Fulcrum's permit application and monitored in the future should the facility be constructed.

As you're aware, Gary meets many of the factors considered for an EPA Environmental Justice Community: Disproportionate exposure to environmental harms and risks, persistent environmental health disparities, racial inequity, low income, high unemployment, and lack of opportunity for public input in decision making.

The historical and ongoing disparity has justifiably heightened scrutiny amongst constituents for new industry requiring a FESOP. My constituents have requested and would be reassured by an environmental justice grant and impact analysis.

At this time, we all request that you place a hold on the permit and allow evaluation of the impact from the Sierra biofuels plant. At the minimum, please implement an extension to the 30-day comment period, but we ask for a complete denial.

IDEM Response to Rep. Ragen Hatcher Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source
- IDEM Response to General Statement 12 - Public Hearing

No changes to the draft permit were made as a result of this comment.

Mayor Susan Lynch Statements and IDEM Responses

Mayor Susan Lynch Statements

Yeah, my name is actually Walt Breitinger, and I'm here to represent Mayor Susan Lynch. I'm honored to be invited by her to read a statement that she made, and I'll just read it verbatim.

My name is Sue Lynch. I am the Mayor of Portage, Indiana, the largest city in Porter County. Our city borders Lake County and shares its magnificent Lake Michigan coastline with many cities. I would like to thank you for allowing my comments to be presented by Walt Breitinger, as I am unable to attend tonight due to some scheduling conflicts running the City of Portage.

But tonight I am speaking as a long life resident of Northwest Indiana, someone who truly cares about the environment and has spent many years working on air, land, and water pollution issues with other dedicated, committed environmental organizations to clean up the many messes left by past bad practices.

Facilities like the one being touted here that will turn trash into fuel and energy are not new ideas. They have been around for decades. It is our desperate attempt to rid ourselves of the mountains of garbage that our country produces each year. It is due to our unwillingness to recycle and reduce these volumes of garbage that have gotten us into this mess.

Sadly, I have found these types of facilities are not the pie-in-the-sky answer to our waste woes, as they tend not to want to talk about the other side of the story, the other things that come along with facilities like this. For example, air pollution from trucks will be bringing in mountains of waste not even generated here, needing to processed each day, which will add to our already poor air quality, and Northwest Indiana continues to be a nonattainment area due to our poor area quality.

Consider this: 30 trucks operating five times each week could add up to 7,800 trucks per year. What if they operate seven days a week? That would be nearly 11,000 trucks per year. What is the additional load on our air?

Also, impacts to roads. As someone who has lived next to a landfill, I know full well the impact to roads. For example, dirt, dust, debris, wear and tear on the roads themselves, and additional traffic they can bring, not to mention the constant noise to those who live nearby.

Another landfill. The amount of ash produced by waste-to-energy plants can add up to 20 percent of the waste -- of the original waste. Where will that waste go? Fly ash can be toxic and can contain lead, cadmium, copper, zinc, even amounts of dioxin and furans. Where will this ash go? How will it be transported?

Poor oversight by governing agencies. Again, as someone who lived by a landfill, it was my community that bore the burden of paying the watchdogs who had to continually monitor what was going on to make sure the company was complying with the rules and regulations, and many times they were not.

Sadly, and more importantly, is the fact that most of these facilities, over 75 percent, are located in struggling lower-income black and brown communities who have no knowledge of what rules and regulations apply, and who contact -- or who to contact even if they do suspect a violation.

Health issues. We all know that Northwest Indiana has high rates of asthma and brain tumors. According to the U.S. EPA, our state suffers from the largest percent of toxic releases, above every other state in the union. Why on Earth would we want to add any more pollutants to our air?

Further study needs to be done on what this plant will ultimately add to our air quality. We can only do this once, since the original plant in Nevada is not operational. So, we cannot make the determination, at least not yet.

Next, this concept will disincentivize sustainable waste management solutions. As the Porter County Chair of the County Solid Waste Board and someone who promotes waste reduction and recycling, I am concerned that this facility will undermine the work we have done for years, the work we were tasked to do when the State of Indiana created the Solid Waste Districts mandating for us to recycle.

We are literally wiping away years of work. This facility will not only encourage us to become even more of a throwaway society by telling people they can make endless amounts of trash, the fact is it actually encourages us to make more trash to potentially feed this facility. I'm almost done.

So, what is the true cost to operate this facility when you factor in the downside to future generations due to the reckless depletion of our resources? How much will it cost to generate just one gallon of fuel from this facility? What is the rush?

Instead of investing millions of dollars in this facility, why isn't IDEM and the State of Indiana taking a more cautious approach, to see how the Fulcrum facility in Nevada performs, and it seems to continuously have issues and has not gone into full-scale operation.

What is the fuel's performance -- performance? Have any airlines used this fuel in any of their planes, or are they still testing it out? Will 100 percent of the fuel be in planes, or will it be a mixture? What effect does this fuel have on the plane's performance? What about its effect on the actual engine? Was the engine designed for this type of fuel? How will you determine if the plane's engine is or is not being affected by the fuel?

We've tried biodiesel fuel here in Indiana made from soybeans, we've tried ethanol from corn, and they obviously did not work out well. A lot of money is being invested here, and we still do not have good answers.

I would ask IDEM to hold off on this air permit and any other decisions being made on this facility until the plant in Nevada is up and running. Please do your homework. Let's not be hasty. There are too many risks and unanswered questions to move forward at this time.

In closing, please bear in mind that all that glitters is not gold. Thank you. Mayor Sue Lynch.

IDEM Response to Mayor Susan Lynch Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 3 - Truck Traffic, Mobile Source Emissions, Vehicle Noise, Roadway Impacts, and Fugitive Dust from Truck Traffic on Offsite Roads
- IDEM Response to General Statement 4 - Fugitive Dust and Particulate Matter
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

Regarding the comments about ash that will be produced in the proposed biorefinery, unreacted ash and slag that is removed from the syngas will be collected and transported offsite by truck for non-hazardous landfill disposal.

Regarding the comments about dioxin, please see the IDEM Response to George Smolka Statements.

Regarding the comments about the anticipated performance and use of fuel produced in the proposed biorefinery, Fulcrum provided information in its air permit application that indicated that the proposed biorefinery will produce either sulfur-free diesel that meets the American Society for Testing and Materials (ASTM) specification D975 and/or Synthetic Paraffinic Kerosene (SPK) jet fuel to the that meets ASTM specification D7655. In addition, Fulcrum provided information on its website (https://centerpoint.fulcrum-bioenergy.com/) stating than current sustainable aviation fuel specifications require that it be blended with traditional jet fuel (up to 50%) prior to delivery to customers, that ASTM is examining the use of 100% sustainable aviation fuel in aircraft engines, and that United Airlines recently conducted a flight using 100% sustainable aviation fuel in one engine as a demonstration.

No changes to the draft permit were made as a result of this comment.

Walt Breitinger Statements and IDEM Responses

Walt Breitinger Statements

Yeah, my name is Walt Breitinger, and I'm from Valparaiso, originally from Philadelphia, and my first jobs were at the corner -- well, on Broadway, my first major job was at the corner of Fifth and Broadway in the late '60's.

I worked here in Gary during what was called the white flight. The people of Gary, for this past 40 or 45 years, have been hoodwinked, lied to, abused by business, by government, by industry. They've often trusted and believed all kinds of schemes and scams, not because they're gullible or poorly educated, but they've been desperate for good employment, desperate for good clean businesses like Fulcrum promises to be.

The waste-to-energy concept, I think, is very interesting, and it might be successful someday, but not here, not now. We're not ready for this. It's not ready for us. Please give us as a community some more time, and give them some more time to follow through with the Nevada plant and see how it works.

And please do not issue any permits to experiment on people. If this plant is going to be built somewhere soon, put it in a neighborhood where there are plenty of rich white people. See how it works out there. Thank you.

IDEM Response to Walt Breitinger Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents

No changes to the draft permit were made as a result of this comment.

Rep. Ragen Hatcher Statements and IDEM Responses

Sen. Eddie Melton Statements

Good evening. My name is Eddie Melton. I'm the State Senator for District 3, which includes Gary, Merrillville, Hobart, Crown Point, Lake Station and East Chicago. I want to thank my colleague, Rep. Hatcher, for reading the letter that we all signed as the Gary delegation in opposition of moving this project forward.

I do want to thank you all for coming out and listening. I'm hoping that you truly and sincerely hear the concerns and issues that's being raised tonight. The City of Gary, of course, we want economic development, but we don't want it at the sacrifice of potential health or potential concerns.

A couple of questions I'll ask, and I'll read some remarks I put together. One particular question is: Have our public safety officials been consulted about the mechanics or the logistics of the operations? And if there were to be anything that occurred of catastrophic incidents, have our men and women that come to rescue us and save us and our communities, have they been informed? Have they been a part of the discussions? I think that's a question that we should ask Fulcrum as they continue to move forward.

I want to read a definition that I pulled from the EPA, EPA definition for Environmental Justice, and I quote, the fair treatment and meaningful involvement of all people, regardless of race, color, national origin or income in the development, implementation, and enforcement of environmental laws, regulations and policies. That comes from the EPA.

The City of Gary hasn't been meaningfully involved, according to my constituents. I've received numerous of calls in my office in terms of their concerns of not having enough information to make the best decision on how well this will move forward.

And another issue I think that is -- that we're grappling with is public perception. As we're trying to turn the city around, and we're, both legislatively in our state and here locally, I think the ongoing public perception of waste, of toxicity, of environmental contamination will continue to -- just continue to make the message that Gary is a place that you can dump or have a hazard here in the city. Economic development is a good thing, but again, not at the expense of potential health issues.

As the ranking minority member on the State Appropriations Committee as well as ranking member on the State Budget Committee, I am aware that even IDEM's budget has been cut over the years, over some period of time. My concern is: If there is an incident that would occur, will you all have the capacity to respond or react, and to deliver those services, because of the financial restraints of the cutbacks?

Indiana leads the nation in toxic releases per mile, and is fifth in the number of people living near toxic release facilities. These rankings are in no small part due to heavy manufacturing in and around Gary and the huge populations concentrated around it.

Indiana, again, it was stated earlier, is ranked eighth in lung cancer rates nationwide, and in the rest of the country, lung cancer is vastly overrepresented in black communities. And the young lady that spoke earlier, I, too, had a stepfather that worked in heavy industry, and I would see the soot that would come out of the nose and all those things.

So, she brought these memories back to life for me, and he died of respiratory issues. And myself, growing up in the City of Gary, living right now as an asthmatic person. According to the Hoosier Environmental Council, the degraded air quality resulting from the heavy pollution in industry exposes Gary residents to the eighth highest cancer risk in the nation.

Now I want to go to water quality, and I know my time is limited. Pollution emissions, even emitted once, have a deeply adverse effect on the natural resources we depend on. All of the normal water bodies Gary draws in are marked by the EPA, and I quote, as impaired, as impaired. Each of them contain ammonia, oil and grease, PCB's, and degraded aquatic life, and according to the EPA.

Solid waste to jet fuel, a very new technology that we are aware that is shared with the community. I want to thank those that -- from Fulcrum. I did have a chance to sit down with them, virtually, and to learn a little bit more about it, but it still wasn't enough for me to be convinced that the city or this region was ready and prepared for it.

So, again, I want to thank everybody that came out tonight. I urge you all to extend this period for folks to come and testify and listen and learn, but one of the other things that concerned me is that -- and this is no disrespect to you all -- Gary, far too often, we would have the state come and listen, then turn around and nothing comes of what was shared publicly.

And we're asking, and to many folks in this room that's not even here today, they're looking at this as a life-and-death type of situation. So, I want to let you know, look through the lens of people that truly care and are concerned about their health and their families. This is no grandstanding. These are people that truly have a concern.

So, again, I want to thank you all for coming out.

IDEM Response to Sen. Eddie Melton Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns
- IDEM Response to General Statement 5 - Possible Future Violations
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

The drafting of this proposed permit did not require consultation with public safety officials or emergency preparedness/response officials

The IDEM OLQ Emergency Response program has not seen cutbacks in staffing and has continued to be fully funded. The Emergency Response program is available 24 hours a day to respond as necessary. For information about IDEM Emergency Response program, please see https://www.in.gov/idem/cleanups/investigation-and-cleanup-programs/emergency-response/.

No changes to the draft permit were made as a result of this comment.

Becky Hanscom Statements and IDEM Responses

Becky Hanscom Statements

My name is Becky Hanscom. I've been a resident of Gary for over 30 years, and I came here basically to find out what was going on. I've read this and that in the newspaper, and I'm not a scientist, I'm not a chemist, but what I've heard is that there are a lot of unanswered questions, and what seems to me like a lot of magical thinking about this process that is not proven.

So, I would like to lend my voice to ask you to put a hold on the permitting process until more information can be -- can come out, and I would also like to say shame on anyone that puts their business deals above the health of the community.

IDEM Response to Becky Hanscom Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents
- IDEM Response to General Statement 7 - Local Air Quality, Health and Wellbeing, and Impact of Air Pollution from this Source

No changes to the draft permit were made as a result of this comment.

Wynton Jones Statements and IDEM Responses

Wynton Jones Statements

Hi, everyone. My name's Wynton Jones. I was born and raised in Gary, Indiana. I realize that there's not a whole lot of youth in the room, so I'll just say if the youth was aware, I can assure you that they would detest and go against Fulcrum and their efforts.

I'm a well-educated young man, so I don't have to go through all the list just like everyone else did here to show you all of the different reasons why it's not equitable and reasonable. I just wanted to go ahead and make sure I was here to say this isn't right. So, thank you.

IDEM Response to Wynton Jones Statements

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 1 - Issuance of the Permit
- IDEM Response to General Statement 2 - Environmental Justice and Civil Rights Concerns

No changes to the draft permit were made as a result of this comment.

Penelope Love Statements and IDEM Responses

Penelope Love Statements

Good evening. Thank you so much for allowing me to come up. I'll only be a moment. I really didn't have any questions, actually. I just wasn't quite sure how to take all of this in, but I was just reading the paper that you have out here, the Citizen Summary, and I have to ask, without challenge, necessarily: Is this an impartial hearing?

Because as I'm reading this, it says the effect of the permit, if approved by IDEM's Office of Air Quality the proposed permit would allow Fulcrum Centerpoint to construct and operate a new biorefinery, then it goes to say the biorefinery will accept a process engineering feedstock for Fischer-Tropsch gasification.

The ultimate product will be low carbon renewal transportation fuel. Feedstock for the biorefinery will be produced off-site at separate facilities from municipal waste, et cetera, et cetera. The biorefinery will not incinerate -- I'm just curious. You've made all of these assertions, but are these proven? Is this really an impartial hearing board?

IDEM Response to Penelope Love Statements

IDEM, OAQ conducts public hearings on an objective, consistent, and impartial basis.

As explained in the Citizen Summary provided at the public hearing and by the public hearing officer at the beginning of the public hearing, the purpose of the public hearing was to allow for the public to provide testimony regarding the draft FESOP and New Source Construction permit for Fulcrum Centerpoint, LLC. A court reporter attends public hearings and makes an official record (transcript) of all of the comments and questions made during the public hearing.

During a public hearing, IDEM, OAQ does not provide responses to questions or comments made during the hearing. However, IDEM reviews all comments and questions received during the hearing, and submitted as part of the public comment period, and after careful consideration, provides detailed responses in writing as part of the final decision. IDEM, OAQ's comment

responses are included in the Addendum to the Technical Support Document (ATSD), and the ATSD is part of the final permit documents when IDEM issues its final decision.

Please see the following IDEM responses at the beginning of the ATSD under the General Statements and IDEM Responses section:

- IDEM Response to General Statement 6 - Employment, Quality of Life, Noise, Zoning, Water Pollution, Land Pollution, Sustainability Issues, Economic/Feasibility Issues, No Proven Track Record, and Accidents

No changes to the draft permit were made as a result of this comment.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Andrew Belt, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-3217 or (800) 451-6027, and ask for Andrew Belt or (317) 232-3217.

(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 Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a New Source Construction and Federally Enforceable State Operating Permit (FESOP)

Source Description and Location

Source Name:	**Fulcrum Centerpoint, LLC**
Source Location:	**6200 Industrial Highway, Gary, Indiana 46406**
County:	**Lake (Calumet)**
SIC Code:	**2999 (Products of Petroleum and Coal, Not Elsewhere Classified)**
Operation Permit No.:	**F089-44042-00660**
Permit Reviewer:	**Andrew Belt**

On April 30, 2021, the Office of Air Quality (OAQ) received an application from Fulcrum Centerpoint, LLC related to the construction and operation of a new stationary biorefinery.

Existing Approvals

There have been no previous approvals issued to this source.

County Attainment Status

The source is located in Lake County (Calumet Township).

Pollutant	Designation
SO_2	Better than national standards.
CO	Attainment effective February 18, 2000, for the part of the city of East Chicago bounded by Columbus Drive on the north; the Indiana Harbor Canal on the west; 148th Street, if extended, on the south; and Euclid Avenue on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of East Chicago and Lake County.
O_3	Serious nonattainment effective September 23, 2019, for the 2008 8-hour ozone standard.
O_3	Marginal nonattainment effective August 3, 2018, for the 2015 8-hour ozone standard for Calumet Township, Hobart Township, North Township, Ross Township, and St. John Township. Unclassifiable or attainment effective August 3, 2018, for the 2015 8-hour ozone standard for the remainder of the county.
$PM_{2.5}$	Unclassifiable or attainment effective January 28, 2019, for the 2012 annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour $PM_{2.5}$ standard.
PM_{10}	Attainment effective March 11, 2003, for the cities of East Chicago, Hammond, Whiting, and Gary. Unclassifiable effective November 15, 1990, for the remainder of Lake County.
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO_2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(a) Ozone Standards
U.S. EPA, in the Federal Register Notice 84 FR 44238 dated August 23, 2019, designated Lake County as serious nonattainment for the 2008 8-hour ozone standard effective September 23, 2019. Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Therefore, VOC and NOx emissions were evaluated pursuant to the requirements of Emission Offset, 326 IAC 2-3.

(b) $PM_{2.5}$
Lake County has been classified as attainment for $PM_{2.5}$. 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
Lake County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this type of operation is not one (1) of the twenty-eight (28) listed source categories under 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B), and there is no applicable New Source Performance Standard or National Emission Standard for Hazardous Air Pollutants that was in effect on August 7, 1980, fugitive emissions are not counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Background and Description of Emission Units and Pollution Control Equipment

The Office of Air Quality (OAQ) has reviewed an application, submitted by Fulcrum Centerpoint, LLC on April 30, 2021, relating to Fulcrum Centerpoint, LLC proposing to construct and operate a new biorefinery. The biorefinery will accept a Processed Engineered Feedstock ("Feedstock") for its gasification, Fischer-Tropsch ("FT") liquids and renewable transportation fuel production process. The ultimate product will be low carbon, renewable transportation fuels. Feedstock for the biorefinery will be produced offsite at separate facilities from Municipal Solid Waste ("MSW"), otherwise destined for landfills in Indiana and Illinois, and then transported to the biorefinery in trucks. The Project will not incinerate or combust MSW, rather it will convert Feedstock into low carbon, renewable transportation fuel.

The following is a list of the new emission units and pollution control device(s):

(a) Three (3) feedstock storage buildings, identified as FDSTG-1, FDSTG-2, and FDSTG-3, approved in 2022 for construction, with a combined maximum capacity of 1,650 tons per day, each using a baghouse for particulate control, and exhausting to stack SV1.

(b) Three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, approved in 2022 for construction, with a maximum throughput of 550 tons per day and a maximum heat input capacity of 30.73 MMBtu/hr, each, equipped with low-NOx burners, each using a baghouse for particulate control, and exhausting to stack SV2.

(c) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, approved in 2022 for construction, each with a maximum throughput of 550 tons per day and rated at 115,000 pounds of syngas produced per hour, each, and consisting of:

(1) Three (3) steam reformers, equipped with three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, with a maximum heat input capacity of 75.6 MMBtu/hr, each, using a SCR system for NOx control, and exhausting to stacks SV5, SV6, and SV7;

(2) Three (3) carbon trim cells (CTC);

(3) Three (3) partial oxidation (POx) units;

(4) Three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3; and

Under 40 CFR 60, Subpart Dc, the heat recovery steam generators (HRSGs) are considered affected facilities.

(5) One (1) flare, identified as FLA, with a maximum start-up gas flow rate of 1,107 MMBtu/hr, and exhausting to stack SV9.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

Under 40 CFR 60, Subpart RRR, the gasifier trains and related processes are considered affected facilities.

(d) Three (3) ash silos, identified as ASH1, ASH2, and ASH3, approved in 2022 for construction, with a maximum loading rate of 1.0 ton/hr, each, using baghouses for particulate control, and exhausting to stack SV3.

(e) Three (3) bed media silos, identified as BMS1, BMS2, and BMS3, approved in 2022 for construction, with a maximum loading rate of 0.23 tons per hour, using baghouses for particulate control, and exhausting to stack SV4.

(f) One (1) sulfur removal unit, identified as SRU, approved in 2022 for construction, with a maximum airflow rate of 27,068 acfm, using an amine-based acid gas removal system to remove hydrogen sulfide and carbon dioxide from syngas, and exhausting to stack SV8.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

(g) One (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, approved in 2022 for construction, converting syngas into FT liquids (syncrude), with a maximum feedstock equivalent capacity of 1,650 tons per day. The FT liquids are thermally separated into a heavy FT liquid stream (HFTL) and a medium FT liquid stream (MFTL). The water generated in the FT process is separated from the MFTL and sent to the wastewater treatment facility. The HFTL and MFTL are sent to the HFTL and MFTL intermediate storage tanks. Unreacted syngas is separated from the MFTL and either recycled back to the FT reactor, sent to the POx units for

methane reforming or combusted in the utility boiler as purge gas. The HFTL and MFTL hydrocarbon streams are sent from the intermediate storage tanks to the syncrude upgrading section.

(h) One (1) utility boiler, identified as BOIL, approved in 2022 for construction, with a maximum heat input capacity of 249.20 MMBtu/hr for natural gas and 36.80 MMBtu/hr for purge gas, using a SCR for NOX control and an oxidation catalyst for VOC and CO control, and exhausting to stack SV10.

Under the 40 CFR 60, Subpart Db, this is considered an affected facility.

(i) One (1) external floating roof HFTL storage tank, identified as T6, approved in 2022 for construction, with a maximum storage capacity of 73,000 gallons, and exhausting indoors.

(j) One (1) external floating roof MFTL storage tank, identified as T7, approved in 2022 for construction, with a maximum storage capacity of 94,300 gallons, and exhausting indoors.

(k) One (1) syncrude upgrading section, cracking syncrude from the FT synthesis reactor into Synthetic Paraffinic Kerosene (SPK) and naptha, consisting of the following:

(1) One (1) hydrocracker heater, identified as HYCR, approved in 2022 for construction, with a maximum heat input capacity of 9.70 MMBtu/hr, and exhausting to stack SV11.

(2) One (1) fractionator heater, identified as FRAC, approved in 2022 for construction, with a maximum heat input capacity of 9.70 MMBtu/hr, and exhausting to stack SV12.

(3) One (1) product stripper heater, identified as PSH, approved in 2022 for construction, with a maximum heat input capacity of 3.70 MMBtu/hr, and exhausting to stack SV13.

(l) Three (3) vertical fixed roof product storage tanks, identified as T1, T2, and T3, approved in 2022 for construction, with a maximum storage capacity of 587,000 gallons of SPK, each, and exhausting to vents SV14, SV15, and SV16.

(m) One (1) vertical fixed roof off-spec product storage tank, identified as T4, approved in 2022 for construction, with a maximum storage capacity of 216,000 gallons, and exhausting to vent SV17.

(n) One (1) vertical fixed roof solvent sump drum, identified as T5, approved in 2022 for construction, with a maximum storage capacity of 45,000 gallons, and exhausting to vent SV18.

(o) One (1) evaporative cooling tower, identified as CT, approved in 2022 for construction, with a maximum recirculating capacity of 39,990 gpm, and exhausting to the atmosphere.

(p) One (1) wastewater treatment system, identified as WTS, approved in 2022 for construction, with a nominal capacity of 1,426 lpm, as follows:

(1) One (1) equalization tank to buffer the treatment system against variations in wastewater quality and flow, which flows to the pH adjustment tank.

(2) One (1) pH adjustment tank to raise the pH of the wastewater, which flows to the reaction tank.

(3) One (1) reaction tank to allow for chemical addition of a coagulant (ferric chloride) and organosulfide, which removes heavy metals by converting the soluble metals to an insoluble metal sulfide precipitate. The reaction tank feeds a clarifier, where a polymer is added to increase the particle size of the insoluble particles to allow settling within the clarifier. Suspended solids from the wastewater system would be removed with traditional

clarification techniques. Settled solids from clarification would be directed to dewatering equipment.

(4) One (1) neutral tank to adjust the pH of the clarified water with hydrochloric acid to prevent scaling in the downstream filters used to polish the clarifier effluent to achieve low residual solids.

(5) One (1) sludge tank containing sludge produced by the clarifying process, which will be dewatered prior to disposal using plate and frame filter presses. The dewatered solids will be sent to a landfill for disposal and the filtrate collected and recycled back to the front end of the wastewater treatment system.

(q) One (1) truck and railcar loadout system, identified as TRC, approved in 2022 for construction, with a maximum throughput rate of 34,000,000 gallons of synthetic paraffinic kerosene (SPK) per year, using flare LOAD as control, which is supplemented by natural gas, has a maximum heat input capacity of 16.60 MMBtu/hr, and exhausting through stack SV19.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

Under 40 CFR 60, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered affected facilities.

The source also consists of the following insignificant activities:

(a) Vessels storing lubricating oils

(b) Application of grease and lubricants as temporary protective coatings

(c) Replacement or repair of electrostatic precipitators, bags in baghouses and filters in other air filtration equipment

(d) Heat exchanger cleaning and repair

(e) Process vessel degassing and cleaning to prepare for internal repairs

(f) Flue gas conditioning systems and associated chemicals, such as ammonia

(g) Blowdown for utility boilers and cooling towers

(h) Fugitive equipment leak emissions from valves, connectors, and seals

(i) Slag handling activities, approved in 2022 for construction, with a maximum capacity of 1,050 lbs/hr, having no controls, and exhausting to the atmosphere.

(j) One (1) diesel-fired fire pump engine, identified as PUMP, approved in 2022 for construction, with a maximum capacity of 399 hp, and exhausting to stack SV20.

Under 40 CFR 60, Subpart IIII, this is an affected facility.
Under 40 CFR 63, Subpart ZZZZ, this is an affected source.

(k) One (1) diesel-fired emergency generator, identified as EG, approved in 2022 for construction, with a maximum capacity of 28.2 MMBtu/hr, and exhausting to stack SV21.

Under 40 CFR 60, Subpart IIII, this is considered an affected facility.

Under 40 CFR 63, Subpart ZZZZ, this is considered a new affected source.

(l) Four (4) diesel storage tanks, approved in 2022 for construction, with a combined maximum storage capacity of 4,000 gallons.

(m) Paved roads and parking lots with public access

"Integral Part of the Process" Determination

The source submitted the following information to justify why the baghouses should be considered an integral part of the natural gas-fired feedstock dryers (DRYER-1, DRYER-2, and DRYER-3):

(a) Is the primary purpose of the equipment to control air pollution?

While there are obvious pollution control benefits, the primary purpose of the equipment is to provide a safer, cleaner work environment at the proposed facility.

(b) Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?

The baghouses will recover approximately 280 tons per year of material that is then reused in the process by being sent to the gasification trains. This can be done because the makeup of the material is essentially the same as the original material that is combusted and converted to syngas. As a result of this recapture, Fulcrum can reduce the required feedstock processing at the offsite waste facility by approximately 550 tons and is able to produce an additional 15,680 gallons per year of product because of the further conversion to FT fuel. The net operational benefit is $172,634 per year. The baghouse system costs approximately $17,000,000, or an annualized cost of $1,980,098. Table 1 below provides a detailed breakdown of the cost savings.

Table 1 - Cost Savings	
Cost Savings	
Recovered Feedstock Amount (tpy)	280
Feedstock Processing Costs ($/ton)	$66.03
Avoided Feedstock Processing Costs ($/yr)[2]	$18,488.40
Avoided Landfill Disposal Costs ($/yr)[3]	$18,200.00
Annual Cost Savings	$36,688.40
Baghouse Operational Cost	
Annual Operational Cost of Baghouse	$1,980,098
Total Annual Benefit ($)	$(1,943,409.60)
[1] Including transport cost [2] Assumes tip fee of $60/ton	

(c) Would the equipment be installed if no air quality regulations are in place?

For the reasons listed in (a), the equipment would be installed without the air quality regulations, as Fulcrum believes in maintaining a clean and safe site.

IDEM, OAQ evaluated the information submitted and has determined that the baghouses should not be considered an integral part of the natural gas-fired feedstock dryers (DRYER-1, DRYER-2, and DRYER-3). This determination is based on the fact that the primary purpose of the baghouse is air pollution control. Therefore, the potential to emit PM, PM10, and PM2.5 from the natural gas-fired feedstock dryers (DRYER) were calculated before the baghouses for purposes of determining permitting level and applicability of 326 IAC 2-2, 326 IAC 2-8-4, and 326 IAC 6.8.

Enforcement Issues

There are no pending enforcement actions related to this source.

Emission Calculations

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

Permit Level Determination – FESOP

This table reflects the unrestricted potential emissions of the source. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Unrestricted Source-Wide Emissions (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**H_2S**	**Total HAPs**
Total PTE of Entire Source Excluding Fugitives*	1,174.98	1,174.98	1,174.98	13.72	170.35	1,410.04	131.82	5.23	5.36
Title V Major Source Thresholds	NA	100	100	100	50	50	100	100	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	100	--
Emission Offset Major Source Thresholds	---	NA	NA	NA	50	50	NA	NA	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."
[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed unrestricted potential emissions of the source.

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM10, PM2.5, and CO are each equal to or greater than one hundred (100) tons per year. The potential to emit of SO2 is less than one hundred (100) tons per year. The source would have been subject to the provisions of 326 IAC 2-7. However, the source will be issued a New Source Construction Permit (326 IAC 2-5.1-3) and a Federally Enforceable State Operating Permit (FESOP) (326 IAC 2-8), because the source will limit emissions to less than the Title V major source threshold levels.

The potential to emit (as defined in 326 IAC 2-7-1(30)) of NOx and VOC is equal to or greater than fifty (50) tons per year. The source would have been subject to the provisions of 326 IAC 2-7. However, the source will be issued a New Source Construction Permit (326 IAC 2-5.1-3) and a Federally Enforceable State Operating Permit (FESOP) (326 IAC 2-8), because the source will limit emissions to less than the Title V major source threshold levels.

(b) The potential to emit (as defined in 326 IAC 2-7-1(30)) of any single HAP is less than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-7-1(30)) of a combination of HAPs is less than twenty-five (25) tons per year. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA).

PTE of the Entire Source After Issuance of the FESOP

The table below summarizes the after issuance source-wide potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this FESOP, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions After Issuance (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**H_2S**	**Total HAPs**
Total PTE of Entire Source Excluding Fugitives*	206.52	74.73	56.20	13.72	44.21	48.73	90.10	5.23	5.36
Title V Major Source Thresholds	NA	100	100	100	50	50	100	100	25
PSD Major Source Thresholds	250	250	250	250	250	250	250	250	--
Emission Offset Major Source Thresholds	---	NA	NA	NA	50	50	NA	NA	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."
[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed potential to emit of the entire source after issuance.

The source opted to take PM, PM10, PM2.5, NOx, VOC, and CO limit(s) in order to render the requirements of 326 IAC 2-7 (Part 70 Permits, 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), and 326 IAC 2-3 (Emission Offset) not applicable to this source. See Technical Support Document (TSD) State Rule Applicability - Entire Source section, 326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset), and 326 IAC 2-8 (FESOP) for more information regarding the limit(s).

(a) This new stationary source is minor under Title V (326 IAC 2-7) because the potential to emit regulated air pollutants and HAPs from the entire source is less than or limited to less than the Title V major source threshold levels. Therefore, the source is subject to the provisions of 326 IAC 2-8 (FESOP) and is an area source under Section 112 of the Clean Air Act (CAA).

(b) This new stationary source is minor under PSD (326 IAC 2-2) because the potential to emit of all PSD regulated pollutants from the entire source is less than or limited to less than the PSD major source thresholds. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

(c) This new stationary source is minor under Emission Offset (326 IAC 2-3) because the potential to emit of all nonattainment regulated pollutant(s), NOx and VOC, from the entire source is less than or limited to less than the Emission Offset major source threshold levels. Therefore, pursuant to 326 IAC 2-3, the Emission Offset requirements do not apply.

Federal Rule Applicability Determination

Federal rule applicability for this source has been reviewed as follows:

New Source Performance Standards (NSPS):

(a) The one (1) utility boiler, identified as BOIL, are subject to the New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, because it has a heat input capacity greater than 100 MMBtu/hr.

The one (1) utility boiler is subject to the following portions of Subpart Db.

(1) 40 CFR 60.40b(a), (g), and (j)
(2) 40 CFR 60.41b
(3) 40 CFR 60.42b(k)(2)
(4) 40 CFR 60.44b(l)(1)
(5) 40 CFR 60.46b(c), (e), and (f)
(6) 40 CFR 60.47b(f)
(7) 40 CFR 60.49b

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the utility boiler except as otherwise specified in 40 CFR 60, Subpart Db.

(b) The three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3, equipped with three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3,are subject to the New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, because each has a heat input capacity less than 100 MMBtu/hr but greater than 10 MMBtu/hr.

The three (3) heat recovery steam generators (HRSGs), identified as HRSG-1, HRSG-2, and HRSG-3, are subject to the following portions of Subpart Dc.

(1) 40 CFR 60.40c(a), (b), and (c)
(2) 40 CFR 60.41c
(3) 40 CFR 60.48c(a) and (g)

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the heat recovery steam generators (HRSGs) except as otherwise specified in 40 CFR 60, Subpart Dc.

(c) This source is subject to the New Source Performance Standards for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60, Subpart VVa and 326 IAC 12, because it is comprised of affected facilities in the *synthetic organic chemicals manufacturing industry*, as defined in 40 CFR 60.481a.

This source is subject to the following portions of Subpart VVa.

(1) 40 CFR 60.480a(a), (b), (c), and (d)
(2) 40 CFR 60.481a
(3) 40 CFR 60.482-1a
(4) 40 CFR 60.482-2a
(5) 40 CFR 60.482-3a
(6) 40 CFR 60.482-4a
(7) 40 CFR 60.482-5a
(8) 40 CFR 60.482-6a
(9) 40 CFR 60.482-7a

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

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the source except as otherwise specified in 40 CFR 60, Subpart VVa.

(d) Three (3) gasifier trains, identified as GT-1, GT-2, and GT-3, are subject to the New Source Performance Standards for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes, 40 CFR 60, Subpart RRR and 326 IAC 12, because although the Fischer-Tropsch ("FT") reactor process produces some of the chemicals listed in §60.707, such as n-butane, hexane, and propane, the vent stream from the reactor process is sent to a boiler before venting post-combustion. The combination of the FT reactor process and the recovery system has a design capacity to produce the chemicals listed in §60.707 at a rate of less than 1 gigagram per year (1,100 tons per year).

This source is subject to the following portions of Subpart RRR.

(1) 40 CFR 60.700(a), (b), and (c)(3)
(2) 40 CFR 60.701
(3) 40 CFR 60.705(i), (l)(5), and (n)

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to this source except as otherwise specified in 40 CFR 60, Subpart RRR.

(e) The one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, are subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because these are *compression ignition (CI) internal combustion engines (ICE)*, as defined in 40 CFR 60.4219.

The one (1) diesel-fired fire pump engine, identified as PUMP, is subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)(ii) and (c)
(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(a), (c), (f)(1), (f)(2)(i), (f)(3), and (g)(2)
(7) 40 CFR 60.4212
(7) 40 CFR 60.4214(b)
(8) 40 CFR 60.4218
(9) 40 CFR 60.4219
(10) Table 4
(11) Table 5
(12) Table 8

The one (1) diesel-fired emergency generator, identified as EG, is subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)(i) and (c)
(2) 40 CFR 60.4202(a)(2)
(3) 40 CFR 60.4205(b)
(4) 40 CFR 60.4206
(5) 40 CFR 60.4207(b)
(6) 40 CFR 60.4208(a) and (h)
(7) 40 CFR 60.4209(a)
(8) 40 CFR 60.4211(a), (c), (f)(1), (f)(2)(i), (f)(3), and (g)(1)
(9) 40 CFR 60.4212
(10) 40 CFR 60.4214(b)
(11) 40 CFR 60.4218
(12) 40 CFR 60.4219
(13) Table 5
(14) Table 8

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the diesel-fired fire pump engine and emergency generator except as otherwise specified in 40 CFR 60, Subpart IIII.

Based on this evaluation, this source is subject to 40 CFR 60, Subpart IIII. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 60.4211(f)(2)(ii) - (iii) of NSPS Subpart IIII. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo:
https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethrough~~ text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 60.4211(f)(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraph~~s~~ (f)(2)(i) ~~through (iii)~~ of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

~~(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the~~

~~Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.~~

~~(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.~~

(f) The requirements of the New Source Performance Standard for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in the permit for the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, and the one (1) product stripper heater, identified as PSH, because these are *process heaters*, as defined in 40 CFR 61b.

(g) The requirements of the New Source Performance Standard for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, are not included in the permit for the one (1) utility boiler, identified as BOIL, because it has a heat input capacity greater than 100 MMBtu/hr.

(h) The requirements of the New Source Performance Standard for Incinerators, 40 CFR 60, Subpart E and 326 IAC 12, are not included in the permit for the source, because it does not burn *solid waste*, as defined in 40 CFR 60.51. The source will convert a process-engineered feedstock, produced offsite at separate facilities from municipal solid waste and convert it into a low carbon, renewable transportation fuel. In addition, Fulcrum's syngas gasification process would not be considered an incinerator as defined in Subpart E (see U.S. EPA Applicability Determination Index (ADI control number 1000019, Conversion of Post-sorted Municipal Solid Waste Feedstock, Douglas K. McDaniel, EPA Region 9 to Patrick D. Traylor).

(i) The requirements of the New Source Performance Standard for Municipal Waste Combustors for Which Construction Is Commenced After December 20, 1989 and On or Before September 20, 1994, 40 CFR 60, Subpart Ea and 326 IAC 12, are not included in the permit for the source, because none of the on-site facilities are a *municipal waste combustor*, as defined in 40 CFR 51a. Additionally, this facility did not commence construction after December 20, 1989 and on or before September 20, 1994.

(j) The requirements of the New Source Performance Standard for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996, 40 CFR 60, Subpart Eb and 326 IAC 12, are not included in the permit for the source, because none of the on-site facilities are a *municipal waste combustor*, as defined in 40 CFR 51b (see U.S. EPA Applicability Determination Index (ADI control number 1000019, Conversion of Post-sorted Municipal Solid Waste Feedstock, Douglas K. McDaniel, EPA Region 9 to Patrick D. Traylor). Finally, the feedstock that is converted to syngas in the gasifier is not considered municipal solid waste since it qualifies as a Non-Hazardous Secondary Material under 40 CFR Part 241, Subpart B.

(k) The requirements of the New Source Performance Standard for New Stationary Sources: Hospital/Medical/Infectious Waste Incinerators, 40 CFR 60, Subpart Ec and 326 IAC 12, are not included in the permit for the source, because it is does not burn *hospital waste* and none of the on-site facilities are a *hospital/medical/infectious waste incinerator*, as defined in 40 CFR 60.51c.

(l) The requirements of the New Source Performance Standard for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60, Subpart Ja and 326 IAC 12, are not included in the permit for this source, because it is not a *petroleum refinery*, as defined in 40 CFR 60.101a.

(m) The requirements of the New Source Performance Standard for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, 40 CFR 60, Subpart Kb and 326 IAC 12, are not

included in the permit for the three (3) product storage tanks, identified as T1, T2, and T3, the one (1) off-spec product storage tank, identified as T4, and the one (1) solvent sump drum, identified as T5, because, while their capacity is greater than 151 m^3, each tank stores a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa).

The requirements of the New Source Performance Standard for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, 40 CFR 60, Subpart Kb and 326 IAC 12, are not included in the permit for the two (2) FT liquid storage tanks, identified as T6 and T7, because these are *process tanks*, as defined in 40 CFR 60.111b.

The requirements of the New Source Performance Standard for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, 40 CFR 60, Subpart Kb and 326 IAC 12, are not included in the permit for the four (4) diesel storage tanks, because these tanks have a combined maximum storage capacity less than 75 cubic meters (m^3).

(n) The requirements of the New Source Performance Standard for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes, 40 CFR 60, Subpart III and 326 IAC 12, are not included in the permit for this source, because it does not produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in §60.617.

(o) The requirements of the New Source Performance Standard for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60, Subpart GGGa and 326 IAC 12, are not included in the permit for this source, because it is not a *petroleum refinery*, as defined in 40 CFR 60.591a.

(p) The requirements of the New Source Performance Standard for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations, 40 CFR 60, Subpart NNN and 326 IAC 12, are not included in the permit for this source, because it does not does not produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in §60.667.

(q) The requirements of the New Source Performance Standard for Petroleum Refinery Wastewater Systems, 40 CFR 60, Subpart QQQ and 326 IAC 12, are not included in the permit for this source, because it is not a *petroleum refinery*, as defined in 40 CFR 60.691.

(r) The requirements of the New Source Performance Standard for Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modifications or Reconstruction is Commenced After June 6, 2001, 40 CFR 60, Subpart AAAA and 326 IAC 12, are not included in the permit for the source, because none of the on-site facilities are a *municipal waste combustion unit*, as defined in 40 CFR 60.1465. According to the U.S. EPA Applicability Determination Index (ADI control number 1000019, Conversion of Post-sorted Municipal Solid Waste Feedstock, Douglas K. McDaniel, EPA Region 9 to Patrick D. Traylor), Subpart AAAA was not applicable to the gasification process at the Fulcrum facility in McCarran, Nevada, for the following reasons:

(i) The project's boiler would not be subject this subpart because it combusts primarily natural gas that is supplemented by the purge gas stream that is produced by the Fischer-Tropsch reactor.

(ii) Since Fulcrum's syngas gasification process is neither combustion nor pyrolysis and would not be considered a "pyrolysis/combustion unit" or "municipal waste combustion unit" as defined in Subpart AAAA.

(iii) If the gasifier were to be considered an MSW combustion unit, the unit would still not be

applicable to this Subpart because the feedstock that is converted to syngas in the gasifier is not considered municipal solid waste since it qualifies as a Non-Hazardous Secondary Material under 40 CFR Part 241, Subpart B.

(s) The requirements of the New Source Performance Standard for Commercial and Industrial Solid Waste Incineration Units, 40 CFR 60, Subpart CCCC and 326 IAC 12, are not included in the permit for the source, because it does not burn *solid waste*, as defined in 40 CFR 258.2. The source will convert a process-engineered feedstock, produced offsite at separate facilities from municipal solid waste and convert it into a low carbon, renewable transportation fuel.

(t) The requirements of the New Source Performance Standard for Commercial and Industrial Solid Waste Incineration Units, 40 CFR 60, Subpart DDDD and 326 IAC 12, are not included in the permit for the source, because it does not burn *solid waste*, as defined in 40 CFR 258.2. The source will convert a process-engineered feedstock, produced offsite at separate facilities from municipal solid waste and convert it into a low carbon, renewable transportation fuel.

(u) The requirements of the New Source Performance Standard for Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006, 40 CFR 60, Subpart EEEE and 326 IAC 12, are not included in the permit for the source, because it does not burn *municipal solid waste* or *institutional waste*, as defined in 40 CFR 60.2977. The source will convert a process-engineered feedstock, produced offsite at separate facilities from municipal solid waste and convert it into a low carbon, renewable transportation fuel.

(v) The requirements of the New Source Performance Standard for Stationary Spark Ignition Internal Combustion Engines, 40 CFR 60, Subpart JJJJ and 326 IAC 12, are not included in the permit for the one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, because these are not *spark ignition internal combustion engines*, as defined in 40 CFR 60.4248.

(w) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) The one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because these are stationary reciprocating internal combustion engines (RICE) located at an area source of HAPs.

The one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, is subject to the following portions of Subpart ZZZZ:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)
(4) 40 CFR 63.6595(a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

Pursuant to 40 CFR 63.6665, the diesel-fired fire pump engine and emergency generator do not have to meet the requirements of 40 CFR 63, Subpart A (General Provisions), since each is considered a new stationary RICE located at an area source of HAP emissions.

Based on this evaluation, this source is subject to 40 CFR 63, Subpart ZZZZ. On May 4, 2016,

the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 63.6640(f)(2)(ii) - (iii) of NESHAP Subpart ZZZZ. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo:
https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethrough~~ text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 63.6640(f)(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraph~~s~~ (f)(2)(i) ~~through (iii)~~ of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

~~(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.~~

~~(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.~~

(b) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) from the Synthetic Organic Chemical Manufacturing Industry, Subpart F are not included in the permit for the source, because the source is not a major source of HAPs.

(c) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater, Subpart G are not included in the permit for the source, because the source is not a major source of HAPs.

(d) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) from Equipment Leaks, Subpart H are not included in the permit for the source, because the source is not a major source of HAPs.

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks, Subpart I are not included in the permit for the source, because the source is not a major source of HAPs.

(f) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Process Cooling Towers, 40 CFR 63, Subpart Q and 326 IAC 20-4 are not included in the permit for the one (1) evaporative cooling tower, identified as CT, because the source is not a major source of HAPs.

(g) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), 40 CFR 63, Subpart R and 326 IAC 20-10 are not included in the permit for the source, because the source is not a *bulk gasoline terminal*, as defined in 40 CFR 63.421.

(h) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Marine Tank Vessel Loading Operations, 40 CFR 63, Subpart Y and 326 IAC 20-17 are not included in the permit for the source, because the source is not a *marine tank vessel loading operation*, as defined in 40 CFR 63.561.

(i) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Petroleum Refineries, 40 CFR 63, Subpart CC and 326 IAC 20-16 are not included in the permit for the source, because the source is not a major source of HAPs.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, 40 CFR 63, Subpart UUU and 326 IAC 20-50 are not included in the permit for the source, because the source is not a petroleum refinery.

(k) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Organic Liquids Distribution (Non-Gasoline), 40 CFR 63, Subpart EEEE and 326 IAC 20-83 are not included in the permit for this source, because the source is not a major source of HAPs.

(l) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Miscellaneous Organic Chemical Manufacturing, 40 CFR 63, Subpart FFFF and 326 IAC 20-84 are not included in the permit for the source, because the source is not a major source of HAPs.

(m) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Major Sources: Industrial, Commercial, and Institutional Utility boilers and Process Heaters, 40 CFR 63, Subpart DDDDD and 326 IAC 20-95 are not included in the permit for the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) utility boiler, identified as BOIL, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, and the one (1) product stripper heater, identified as PSH, because the source is not a major source of HAPs.

(n) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities, 40 CFR 63, Subpart BBBBBB are not included in the permit for this source, because it is not a *bulk gasoline terminal*, *bulk gasoline plant*, or a *pipeline facility*, as in 40 CFR 63.11100.

(o) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ are not included in the permit for the one (1) utility boiler, identified as BOIL, because it meets the definition of a *waste heat boiler*, as defined by 40 CFR 63.11237, and is specifically excluded from the definition of a *boiler*, as defined by 40 CFR 63.11237.

(p) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Chemical Manufacturing Area Sources, 40 CFR 63, Subpart VVVVVV are not included in the permit for this source, because this source does not have any Table 1 HAPs present in feedstocks, or Table 1 HAPs that are generated or produced in Chemical Manufacturing Process

Units (CMPU) and are present in process fluid at concentrations greater than 0.1 percent for carcinogens or greater than 1.0 percent for non-carcinogens.

(q) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Area Sources: Chemical Preparations Industry, 40 CFR 63, Subpart BBBBBBB are not included in the permit for this source, because it does not operate a *chemical preparations facility* as defined in 40 CFR 63.11588.

(r) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 63, 326 IAC 14 and 326 IAC 20 included in the permit.

Compliance Assurance Monitoring (CAM):

Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is not included in the permit, because the unlimited potential to emit of the source is limited to less than the Title V major source thresholds and the source is not required to obtain a Part 70 or Part 71 permit.

State Rule Applicability - Entire Source

State rule applicability for this source has been reviewed as follows:

326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset)
PSD, and Emission Offset applicability is discussed under the PTE of the Entire Source After Issuance of the FESOP section of this document.

PSD/EO Minor Source Limit(s)

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 2-3 (Emission Offset) not applicable, the Permittee shall comply with the following:

(a) PM, PM10, and PM2.5 emissions from the units named in the table below shall not exceed the values shown in the table:

Unit Description	Control Device	PM Emission Limit (lbs/hr)	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
Feedstock Storage Building (FDSTG-1)	Baghouse	12.86	2.83	1.42
Feedstock Storage Building (FDSTG-2)	Baghouse	12.86	2.83	1.42
Feedstock Storage Building (FDSTG-3)	Baghouse	12.86	2.83	1.42
Feedstock Dryer (DRYER-1)	Baghouse	1.20	1.20	1.20
Feedstock Dryer (DRYER-2)	Baghouse	1.20	1.20	1.20
Feedstock Dryer (DRYER-3)	Baghouse	1.20	1.20	1.20
Ash Silo (ASH1)	Baghouse	0.055	0.055	0.055
Ash Silo (ASH2)	Baghouse	0.055	0.055	0.055
Ash Silo (ASH3)	Baghouse	0.055	0.055	0.055
Bed Media Silo (BMS1)	Baghouse	0.055	0.055	0.055
Bed Media Silo (BMS2)	Baghouse	0.055	0.055	0.055
Bed Media Silo (BMS3)	Baghouse	0.055	0.055	0.055

(b) The emergency generator shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) NOx emissions from the emergency generator shall not exceed 0.024 pounds per horsepower hour.

(d) VOC emissions from the emergency generator shall not exceed 0.000705 pounds per horsepower hour.

(e) The fire pump engine shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

(f) NOx emissions from the fire pump engine shall not exceed 0.031 pounds per horsepower hour.

(g) VOC emissions from the fire pump engine shall not exceed 0.0025 pounds per horsepower hour.

(h) Total NOx emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater shall not exceed 41.91 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

(i) Total VOC emissions from FT reactor, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks shall not exceed 48.12 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

Compliance with these limits, combined with the potential to emit PM, PM10, PM2.5, NOx, and VOC from all other emission units at this source, shall limit the source-wide total potential to emit of PM, PM10, PM2.5, NOx, and VOC to less than 100 tons per twelve (12) consecutive month period, each, and NOx and VOC to less than 50 tons per twelve (12) consecutive month period, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 2-3 (Emission Offset) not applicable.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of this source 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 2-6 (Emission Reporting)
This source is subject to the requirements of 326 IAC 2-6 (Emission Reporting), since it is located in Lake County, emits NOx and VOC into the ambient air at levels equal to or greater than twenty-five (25) tons per year. Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit, by July 1, an emission statement covering the previous calendar year each year when the source emits volatile organic compounds or oxides of nitrogen into the ambient air at levels equal to or greater than twenty-five (25) tons during the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 2-8-4 (FESOP)
FESOP applicability is discussed under the PTE of the Entire Source After Issuance of the FESOP section of this document.

<u>FESOP PM10, PM2.5, NOx, VOC, and CO Limit(s)</u>

Pursuant to 326 IAC 2-8-4 (FESOP), and in order to render the requirements of 326 IAC 2-7 (Part 70 Permits), not applicable, the Permittee shall comply with the following:

(a) PM10 and PM2.5 emissions from the units named in the table below shall not exceed the values shown in the table:

Unit Description	Control Device	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
Feedstock Storage Building (FDSTG-1)	Baghouse	2.83	1.42
Feedstock Storage Building (FDSTG-2)	Baghouse	2.83	1.42
Feedstock Storage Building (FDSTG-3)	Baghouse	2.83	1.42
Feedstock Dryer (DRYER-1)	Baghouse	1.20	1.20
Feedstock Dryer (DRYER-2)	Baghouse	1.20	1.20
Feedstock Dryer (DRYER-3)	Baghouse	1.20	1.20
Ash Silo (ASH1)	Baghouse	0.055	0.055
Ash Silo (ASH2)	Baghouse	0.055	0.055
Ash Silo (ASH3)	Baghouse	0.055	0.055
Bed Media Silo (BMS1)	Baghouse	0.055	0.055
Bed Media Silo (BMS2)	Baghouse	0.055	0.055
Bed Media Silo (BMS3)	Baghouse	0.055	0.055

(b) The emergency generator shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) NOx emissions from the emergency generator shall not exceed 0.024 pounds per horsepower hour.

(d) VOC emissions from the emergency generator shall not exceed 0.000705 pounds per horsepower hour.

(e) The fire pump engine shall not operate for more than 100 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.

(f) NOx emissions from the fire pump engine shall not exceed 0.031 pounds per horsepower hour.

(g) VOC emissions from the fire pump engine shall not exceed 0.0025 pounds per horsepower hour.

(h) Total NOx emissions from the feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, and product stripper heater shall not exceed 41.91 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

(i) Total VOC emissions from FT reactor, feedstock dryers, pulse combustors, utility boiler, flare (FLA), hydrocracker heater, fractionator heater, product stripper heater, wastewater treatment system, and storage tanks shall not exceed 48.12 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

(j) CO emissions from the utility boiler shall not exceed 4.63 tons per twelve (12) consecutive month period, with compliance demonstrated at the end of each month.

Compliance with these limits, combined with the potential to emit PM10, PM2.5, NOx, VOC, and CO from all other emission units at this source, shall limit the source-wide total potential to emit of PM10, PM2.5, NOx, VOC, and CO to less than 100 tons per twelve (12) consecutive month period, each, and shall render the requirements of 326 IAC 2-7 (Part 70 Permits) not applicable.

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

(1) Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

326 IAC 6-4 (Fugitive Dust Emissions Limitations)
Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source 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.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
Pursuant to 326 IAC 6-5-1(a), the requirements of 326 IAC 6-5 are not applicable to the source because it is subject to a more stringent limitation under 326 IAC 6.8-10.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
Pursuant to 326 IAC 6.5-1-1(a), this source (located in Lake County) is not subject to the requirements of 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 (Particulate Matter Limitations for Lake County)
This source (located in Lake County) is not one of the sources specifically listed in 326 IAC 6.8-4, 326 IAC 6.8-5, or 326 IAC 6.8-8 through 326 IAC 6.8-11. The source-wide PTE of PM is 10 tons per year or more. Therefore, this source is subject to the requirements of 326 IAC 6.8-1-2 because the source-wide actual emissions of PM can be 10 tons per year or more.

326 IAC 6.8 (Lake County: Fugitive Particulate Matter)
This source (located in Lake County) is not one of the sources specifically listed in 326 IAC 6.8-10-1(2)(A) through (V). The source-wide unlimited PTE of fugitive PM is 5 tons per year or more. Therefore, this source is subject to the requirements of 326 IAC 6.8-10.

(a) Pursuant to 326 IAC 6.8-10-3, the particulate matter emissions from source wide activities shall meet the following requirements:

(1) The average instantaneous opacity of fugitive particulate emissions from a paved road shall not exceed ten percent (10%).

(2) The average instantaneous opacity of fugitive particulate emissions from an unpaved road shall not exceed ten percent (10%).

(3) The opacity of fugitive particulate emissions from exposed areas shall not exceed ten percent (10%) on a six (6) minute average.

(4) The opacity of fugitive particulate emissions from continuous transfer of material onto and out of storage piles shall not exceed ten percent (10%) on a three (3) minute average.

(5) The opacity of fugitive particulate emissions from storage piles shall not exceed ten percent (10%) on a six (6) minute average.

(6) There shall be a zero (0) percent frequency of visible emission observations of a material during the inplant transportation of material by truck or rail at any time.

(7) The opacity of fugitive particulate emissions from the inplant transportation of material by front end loaders and skip hoists shall not exceed ten percent (10%).

(8) Material processing facilities shall include the following:

(A) There shall be a zero (0) percent frequency of visible emission observations from a building enclosing all or part of the material processing equipment, except from a vent in the building.

(B) The PM10 emissions from building vents shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(C) The PM10 stack emissions from a material processing facility shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(D) The opacity of fugitive particulate emissions from the material processing facilities, except a crusher at which a capture system is not used, shall not exceed ten percent (10%) opacity.

(E) The opacity of fugitive particulate emissions from a crusher at which a capture system is not used shall not exceed fifteen percent (15%).

(9) The opacity of particulate emissions from dust handling equipment shall not exceed ten percent (10%).

(10) Material transfer limits shall be as follows:

(A) The average instantaneous opacity of fugitive particulate emissions from batch transfer shall not exceed ten percent (10%).

(B) Where adequate wetting of the material for fugitive particulate emissions control is prohibitive to further processing or reuse of the material, the opacity shall not exceed ten percent (10%), three (3) minute average.

(C) Slag and kish handling activities at integrated iron and steel plants shall comply with the following particulate emissions limits:

(i) The opacity of fugitive particulate emissions from transfer from pots and trucks into pits shall not exceed twenty percent (20%) on a six (6) minute average.

(ii) The opacity of fugitive particulate emissions from transfer from pits into front end loaders and from transfer from front end loaders into trucks shall comply with the fugitive particulate emission limits in 326 IAC 6.8-10-3(9).

(11) Any facility or operation not specified in 326 IAC 6.8-10-3 shall meet a twenty percent (20%), three (3) minute average opacity standard.

The Permittee shall achieve these limits by controlling fugitive particulate matter emissions according to the Fugitive Dust Control Plan, which is included as Attachment A to the permit.

326 IAC 8-6 (Organic Solvent Emission Limitations)
The source is not subject to the requirements of 326 IAC 8-6, because it was constructed after January 1, 1980.

326 IAC 8-18 (Synthetic Organic Chemical Manufacturing Industry Air Oxidation, Distillation, and Reactor Processes)
The source is not subject to the requirements of 326 IAC 8-18, because it does not produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in §60.617.

326 IAC 8-19 (Control of Volatile Organic Compound Emissions from Process Vents in Batch Operations)
The source is not subject to the requirements of 326 IAC 8-19, because while it has a batch process train associated with SIC code 2869, VOC emissions from the batch process train are less than one hundred (100) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The source is a stationary source of CO emissions that commenced operation after March 21, 1972. However, the source is not one of the types for sources for which an emission limit is established in 326 IAC 9-1-2.

State Rule Applicability – Individual Facilities

State rule applicability for this source has been reviewed as follows:

Feedstock Storage and Handling

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1(b)(11), the three (3) feedstock storage buildings, identified as FDSTG-1, FDSTG-2, and FDSTG-3, are not subject to the requirements of 326 IAC 6-3, since it is subject to a more stringent limitation under 326 IAC 6.8.

326 IAC 6.8-1-2 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the three (3) feedstock storage buildings, identified as FDSTG-1, FDSTG-2, and FDSTG-3, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot

(dscf)), each

Feedstock Dryers

326 IAC 6-2 (Particulate Emissions from Indirect Heating Units)
The three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, are not subject to the requirements of 326 IAC 6-2 since each is not a source of indirect heating. The feedstock is passed via conveyor through rotating drum dryers, where hot air reduces the feedstock moisture

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 1-2-59, the three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, are exempt from the requirements of 326 IAC 6-3-2, since liquid and gaseous fuels and combustion air are not considered as part of the process weight rate.

326 IAC 6.8-1-2 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot (dscf)), each.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
The three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, are not subject to the requirements of 326 IAC 7-1.1, because each has unlimited SO_2 potential emissions of less than twenty-five (25) tons per year, and ten (10) pounds per hour.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)
The three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, are not subject to the requirements of 326 IAC 8-1-6, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per year.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark, and Floyd Counties)
The three (3) natural gas-fired feedstock dryers, identified as DRYER-1, DRYER-2, and DRYER-3, are not subject to the requirements of 326 IAC 8-7, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per year.

Silo Emissions

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1(b)(14), the three (3) ash silos, identified as ASH1, ASH2, and ASH3, and the three (3) bed media silos, identified as BMS1, BMS2, and BMS3, are not subject to the requirements of 326 IAC 6-3, since these are subject to a more stringent limitation under 326 IAC 6.8.

326 IAC 6.8-1-2 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the three (3) ash silos, identified as ASH1, ASH2, and ASH3, and the three (3) bed media silos, identified as BMS1, BMS2, and BMS3, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot (dscf)), each.

Fischer Tropsch (FT) Synthesis Reactor

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
The one (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, is subject to the requirements of 326 IAC 8-1-6, because it was constructed after January 1, 1980, and its unlimited VOC potential emissions are equal to or greater than twenty-five (25) tons per year, and the Fischer Tropsch (FT) Synthesis reactor is not regulated by other rules in 326 IAC 8. Therefore, a Best Available

Control Technology (BACT) analysis was required for the Fischer Tropsch (FT) Synthesis reactor (see Appendix B of this TSD).

According to the BACT analysis contained in Appendix B of this TSD, IDEM, OAQ has determined that the following requirements represent BACT for the one (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor:

(a) The VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor shall be controlled by the utility boiler (BOIL) except when flaring the VOC emissions during startup and shutdown.

(b) The utility boiler (BOIL) shall operate with an overall VOC control efficiency (including the capture efficiency and destruction efficiency) of not less than 98.0% or the VOC outlet concentration shall not exceed 10 ppmvd of VOC at 100% capture.

(c) VOC emissions from the utility boiler stack (SV10) shall not exceed 1.23 lb/hr.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark, and Floyd Counties)
The one (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, is not subject to the requirements of 326 IAC 326 IAC 8-7, since this is subject to more stringent limits under 326 IAC 8-1-6.

Natural Gas-Fired Units

326 IAC 3-5 (Continuous Monitoring of Emissions)
(a) The one natural gas and purge gas fired (1) utility boiler, identified as BOIL, is subject to the monitoring requirements of 326 IAC 3-5 because it is a fossil fuel-fired steam generator of greater than one hundred million (100,000,000) British thermal units (Btu) per hour heat input capacity. The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx emissions since it is equipped with NOx pollution control equipment and a monitor is required to determine compliance with 326 IAC 12 (40 CFR 60, Subpart Db).

(b) The three natural gas-fired (3) pulse combustors, identified as PC1, PC2, and PC3 are not subject to the requirements of 326 IAC 3-5 since each combustor has a heat input capacity less than one hundred million (100,000,000) British thermal units (Btu) per hour.

326 IAC 6-2 (Particulate Emissions from Indirect Heating Units)
The three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) utility boiler, identified as BOIL, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, and the one (1) loadout flare, identified as LOAD, are not subject to the requirements of 326 IAC 6-2 since these are subject to a more stringent limitation under 326 IAC 6.8.

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 1-2-59, the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) utility boiler, identified as BOIL, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, and the one (1) loadout flare, identified as LOAD, are exempt from the requirements of 326 IAC 6-3-2, since liquid and gaseous fuels and combustion air are not considered as part of the process weight rate.

326 IAC 6.8-1-2 (Particulate Matter Limitations for Lake County)
(a) Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater,

identified as PSH, the one (1) flare, identified as FLA, and the one (1) loadout flare, identified as LOAD, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot (dscf)), each.

(b) Pursuant to 326 IAC 6.8-1-2(b)(3), particulate matter emissions from the one (1) utility boiler, identified as BOIL, shall not exceed one-hundredth (0.01) grain per dry standard cubic foot (dscf).

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
The three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) utility boiler, identified as BOIL, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, and the one (1) loadout flare, identified as LOAD, are not subject to the requirements of 326 IAC 7-1.1, because each has unlimited SO_2 potential emissions of less than twenty-five (25) tons per year, and ten (10) pounds per hour.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)
The three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) utility boiler, identified as BOIL, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, and the one (1) loadout flare, identified as LOAD, are not subject to the requirements of 326 IAC 8-1-6, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per year.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark, and Floyd Counties)
The three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) utility boiler, identified as BOIL, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, and the one (1) loadout flare, identified as LOAD, are not subject to the requirements of 326 IAC 8-7, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per year.

326 IAC 10-1 (Nitrogen Oxide Control in Clark and Floyd Counties)
The three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, the one (1) utility boiler, identified as BOIL, the one (1) hydrocracker heater, identified as HYCR, the one (1) fractionator heater, identified as FRAC, the one (1) fractionator heater, identified as FRAC, the one (1) product stripper heater, identified as PSH, the one (1) flare, identified as FLA, and the one (1) loadout flare, identified as LOAD, are not subject to the requirements of 326 IAC 10-1, because the source is not located in Clark or Floyd County. The source is located in Lake County.

326 IAC 10-2 (NOx Emissions from Large Affected Units)
The one (1) utility boiler, identified as BOIL, it not subject to this rule because it is not a large affected unit under 326 IAC 10-2-2(c)(11). The utility boiler neither serves a generator producing electricity for sale nor serves a generator producing electricity for sale, if the generator has a nameplate capacity of twenty-five (25) megawatt electrical (MWe) output or less and has the potential to use no more than fifty percent (50%) of the potential electrical output capacity of the unit.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The three (3) natural gas-fired pulse combustors, identified as PC1, PC2, and PC3, and the one (1) utility boiler, identified as BOIL, are not subject to the requirements of 326 IAC 10-3 (Nitrogen Oxides Reduction Program for Specific Source Categories) because these are not Portland cement kilns, described in 326 IAC 10-3-1(a)(1), or one of the affected boilers listed in 326 IAC 10-3-1(a)(2).

Storage Tanks

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)
The three (3) product storage tanks, identified as T1, T2, and T3, the one (1) off-spec product storage tank, identified as T4, the one (1) solvent sump drum, identified as T5, the two (2) FT liquid storage tanks, identified as T6 and T7, and the four (4) diesel storage tanks are not subject to the requirements of 326 IAC 8-1-6, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per year.

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

(a) The three (3) product storage tanks, identified as T1, T2, and T3, the one (1) off-spec product storage tank, identified as T4, the one (1) solvent sump drum, identified as T5, and the two (2) FT liquid storage tanks, identified as T6 and T7, are not subject to the requirements of 326 IAC 8-4-3, because, while the storage tanks have a capacity greater than thirty-nine thousand (39,000) gallons, they do not store volatile organic compounds whose true vapor pressure is greater than 10.5 kPa (1.52 psi). The true vapor pressure is 0.40 psi.

(b) The four (4) diesel storage tanks are not subject to the requirements of 326 IAC 8-4-3, because, these storage tanks have a combined maximum storage capacity less than thirty-nine thousand (39,000) gallons.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark, and Floyd Counties)
The three (3) product storage tanks, identified as T1, T2, and T3, the one (1) off-spec product storage tank, identified as T4, the one (1) solvent sump drum, identified as T5, the two (2) FT liquid storage tanks, identified as T6 and T7, and the four (4) diesel storage tanks are not subject to the requirements of 326 IAC 8-7, because these belong to the volatile organic liquids storage source category in 326 IAC 8-7-2(a)(3)(Q).

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)

(a) Pursuant to 326 IAC 8-9-1(a) and (c), stationary vessels used to store volatile organic liquids (VOL), that are located in Lake County with a capacity greater than or equal to thirty-nine thousand (39,000) gallons that store a VOL with a maximum true vapor pressure less than five-tenths (0.5) pound per square inch absolute (psia) are subject to the reporting and record keeping requirements of this rule. The VOL storage vessels are exempted from all other provisions of this rule.

(b) Pursuant to 326 IAC 8-9-6(a) and (c), the Permittee shall maintain the following records for the life of the stationary storage vessels and submit a report to IDEM, OAQ containing the following for each vessel:

(1) The vessel identification number;

(2) The vessel dimensions; and

(3) The vessel capacity.

(c) Pursuant to 326 IAC 8-9-6(h), the owner or operator of each vessel with a design capacity greater than or equal to thirty-nine thousand (39,000) gallons storing a liquid with a maximum true vapor pressure, as measured in accordance with subsection (f), that is normally less than seventy-five hundredths (0.75) psia shall maintain a record and notify the department within thirty (30) days when the maximum true vapor pressure of the liquid exceeds seventy-five hundredths (0.75) psia.

Fire Pump Engine and Emergency Generator

326 IAC 6-2 (Particulate Emissions from Indirect Heating Units)
The one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, are not subject to the requirements of 326 IAC 6-2 since each is not a source of indirect heating.

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 1-2-59, the one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, are exempt from the requirements of 326 IAC 6-3-2, since liquid and gaseous fuels and combustion air are not considered as part of the process weight rate.

326 IAC 6.8-1-2 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot (dscf)).

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
The one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, are not subject to the requirements of 326 IAC 7-1.1, because each has unlimited SO_2 potential emissions of less than twenty-five (25) tons per year, and ten (10) pounds per hour.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)
The one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, are not subject to the requirements of 326 IAC 8-1-6, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per year.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark, and Floyd Counties)
The one (1) diesel-fired fire pump engine, identified as PUMP, and the one (1) diesel-fired emergency generator, identified as EG, are not subject to the requirements of 326 IAC 8-7, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per year.

Cooling Tower

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1(b)(11), the one (1) evaporative cooling tower, identified as CT, is not subject to the requirements of 326 IAC 6-3, because it is subject to a more stringent limitation under 326 IAC 6.8.

326 IAC 6.8-1-2 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-2(a), particulate matter emissions from the one (1) evaporative cooling tower, identified as CT, shall not exceed seven-hundredths (0.07) gram per dry standard cubic meter (g/dscm) (three-hundredths (0.03) grain per dry standard cubic foot (dscf)).

326 IAC 8-20 (Industrial Wastewater)
The one (1) evaporative cooling tower, identified as CT, is not subject to the requirements of 326 IAC 8-20, because it has unlimited VOC potential emissions of less than one hundred (100) tons per year.

Wastewater Treatment System

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)
The one (1) wastewater treatment system, identified as WTS, is not subject to the requirements of 326 IAC 8-1-6, because each has unlimited VOC potential emissions of less than twenty-five (25) tons per

year.

326 IAC 8-4-2 (Petroleum Refineries)
The one (1) wastewater treatment system, identified as WTS, is not subject to the requirements of 326 IAC 8-4-2, because it is not located at a petroleum refining source.

326 IAC 8-20 (Industrial Wastewater)
The one (1) wastewater treatment system, identified as WTS, is not subject to the requirements of 326 IAC 8-20, because the potential to emit VOC from the entire source is limited to less than one hundred (100) tons per year. Additionally, the source has the SIC code of 2999 (Products of Petroleum and Coal, Not Elsewhere Classified), which is not of the SIC codes listed under 326 IAC 8-20-1(a)(3).

Compliance Determination and Monitoring Requirements

(a) The Compliance Determination Requirements applicable to this source are as follows:

(1) Compliance with the PSD and Emission Offset Minor Limits and FESOP limit (326 IAC 2-2, 326 IAC 2-3, and 326 IAC 2-8-4) for VOC, shall be determined by applying one (1) or more of the following test methods and procedures, as appropriate:

(A) The Permittee shall use one (1) of the following for determining VOC concentration of wastewater samples:

(a) SW-846 Method 5030B (purge and trap) followed by SW-846 Method 8015B with a DB-5 boiling point (or equivalent column), and flame ionization detector, with the detector calibrated with benzene as required by 40 CFR 261*.
(b) SW-846 Methods 3810, 5030B (followed by 8021B), 8260B, and 9060 as required by 40 CFR 261*.
(c) U.S. EPA 40 CFR 136 Methods 602, 624, 1624, 625, 1625*.
(d) U.S. EPA 40 CFR 63 Method 305*.
(e) U.S. EPA 40 CFR 60 Method 25D*.

In the event of any conflict, U.S. EPA 40 CFR 60 Method 25D* takes precedence.

(B) Flow rate measurements shall be taken at the same time as the concentration measurements.

(2) The source shall determine the VOC emissions of each storage tank in accordance with Section 7.1.3.1 – Routine Losses From Fixed Roof Tanks, Section 7.1.3.2 – Routine Losses From Floating Roof Tanks, and Section 7.1.3.4 – Tank Cleaning Emissions (ref: Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42, 5th Edition, U.S. EPA OAQPS, June 2020) or subsequent editions of the references for those AP-42 sections; Evaporative Loss from Fixed-roof Tanks, Manual of Petroleum Measurement Standards, Chapter 19.1, Fifth Edition, American Petroleum Institute, Washington, D.C., June 2017 and Evaporative Loss from Storage Tank Floating Roof Landings, Manual of Petroleum Measurement Standards, Chapter 19.6, Part 1, First Edition, American Petroleum Institute, Washington, D.C., February 2017; or Evaporative Loss from the Cleaning of Storage Tanks, Technical Report 2568, American Petroleum Institute, Washington, D.C., November 2007.

(3) In order to demonstrate compliance with 326 IAC 2-2, 326 IAC 2-3, and 326 IAC 2-8-4, the Permittee shall determine the NOx, VOC, and CO emissions for each month using the following equations:

(A) NOx Emissions:

$$NOx\left(\frac{tons}{month}\right) = \frac{FD(Ef_{FD}) + PC(Ef_{PC}) + B(Ef_B) + F(Ef_{FP}) + FSUSD(Ef_{FSUSD}) + H(Ef_H)}{2{,}000\ lbs/ton}$$

Where:
FD = Feedstock dryers natural gas heat input (MMBtu/month)
Ef_{FD} = 0.030 lb of NOx per MMBtu or the NOx emission rate determined in the most recent stack test (lb/MMBtu)
PC = Pulse combustors natural gas heat input (MMBtu/month)
Ef_{PC} = 0.0089 lb of NOx per MMBtu or the NOx emission rate determined in the most recent stack test (lb/MMBtu)
B = Utility boiler combined natural gas and purge gas heat input (MMBtu/month)
Ef_B = 0.0061 lb of NOx per MMBtu or the NOx emission rate determined in the most recent stack test (lb//MMBtu) until the CEMS required by Condition D.1.14 begins operation. Then NOx emissions from the utility boiler shall be determined for the month being reported from the CEMS, lb/month.
F = Flare Pilot natural gas usage (MMScf/month)
Ef_{FP} = 100 lb of NOx per MMscf
FSUSD = Flare heat input during startup and shutdown (MMBtu/month)
Ef_{FSUSD} = 0.068 lb of NOx per MMBtu
H = Hydrocracker, Fractionator, and Product Stripper combined natural gas usage (MMscf/month)
Ef_H = 100.00 lb of NOx per MMscf of natural gas

(B) VOC Emissions:

$$VOC\left(\frac{tons}{month}\right) = \frac{FD(Ef_{FD}) + PC(Ef_{PC}) + B(Ef_B) + F(Ef_{FP}) + FSUSD(Ef_{FSUSD}) + H(Ef_H) + ST + (WT\ x\ WT_{VOC}\ x\ f_e)}{2{,}000\ lbs/ton}$$

Where:
FD = Feedstock dryers natural gas heat input (MMscf/month)
Ef_{FD} = 5.5 lb of VOC per MMscf
PC = Pulse combustors natural gas heat input (MMBtu/month)
Ef_{PC} = 0.00556 lb of VOC per MMBtu or the VOC emission rate determined in the most recent stack test (lb/MMBtu)
B = Utility boiler combined natural gas and purge gas heat input (MMBtu/month)
Ef_B = 0.00016 lb of VOC per MMBtu or the VOC emission rate determined in the most recent stack test (lb//MMBtu)
F = Flare Pilot natural gas usage (MMScf/month)
Ef_{FP} = 5.5 lb of VOC per MMscf
FSUSD = Flare heat input during startup and shutdown (MMBtu/month)
Ef_{FSUSD} = 0.14 lb of VOC per MMBtu
H = Hydrocracker, Fractionator, and Product Stripper combined natural gas usage (MMscf/month)
Ef_H = 5.5 lb of VOC per MMscf of natural gas
ST = monthly VOC emissions from storage tanks (lb/month)
WT = Wastewater flow (gallons per month)
WT_{VOC} = VOC concentration (0.00027 lb/gal or the VOC content determined in

the most recent sampling)
f_e = 0.683 (weighted average value from EPA 453 D-93-056)

(C) CO Emissions:

$$CO\left(\frac{tons}{month}\right) = \frac{B(Ef_B)}{2{,}000\ lbs/ton}$$

Where:
B = Utility boiler combined natural gas and purge gas heat input (MMBtu/month)
Ef_B = 0.0037 lb of CO per MMBtu or the CO emission rate determined in the most recent stack test (lb//MMBtu)

(4) In order to assure compliance with 326 IAC 2-2, 326 IAC 2-3, 326 IAC 2-8-4, and 326 IAC 6.8-1-2(a), the baghouses for particulate control shall be in operation and control emissions from the feedstock dryers at all times the feedstock dryers are in operation.

(5) In order to assure compliance with 326 IAC 6.8-1-2(a), the baghouse for particulate control shall be in operation and control emissions from the feedstock storage at all times the feedstock storage is in operation.

(6) In order to assure compliance with 326 IAC 6.8-1-2(a), the filters for particulate control shall be in operation and control emissions from the ash silos and bed media silos at all times the ash silos and bed media silos are in operation.

(7) In order to assure compliance with 326 IAC 2-8-4 and to render the requirements of 326 IAC 2-2 and 326 IAC 2-3 not applicable, the selective catalytic reduction (SCR) system for NOx control shall be in operation and control emissions from the pulse combustors and utility boiler at all times the pulse combustors and utility boiler are in operation.

(8) In order to assure compliance with 326 IAC 2-8-4 and to render the requirements of 326 IAC 2-2 and 326 IAC 2-3 not applicable, the oxidation catalyst for VOC and CO control shall be in operation and control emissions from the utility boiler at all times the utility boiler is in operation.

(9) In order to assure compliance with 326 IAC 2-8-4 and to render the requirements of 326 IAC 2-2 and 326 IAC 2-3 not applicable, the utility boiler for VOC control shall be in operation and control emissions from the FT Reactor at all times the FT Reactor is in operation, except during periods of startup and shutdown.

(10) In order to assure compliance with 326 IAC 2-8-4 and to render the requirements of 326 IAC 2-2 and 326 IAC 2-3 not applicable, the flare (FLA) for VOC control shall be in operation and control emissions from the gasifier trains (GT-1, GT-2, and GT-3) and FT reactor during periods of startup and shutdown.

(11) In order to assure compliance with 326 IAC 2-8-4 and to render the requirements of 326 IAC 2-2 and 326 IAC 2-3 not applicable, not later than 180 days after initial start-up, the Permittee shall analyze the purge gas stream from the FT Reactors for the VOC and HAPs content. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(12) Not later than ninety (90) after analyzing the purge gas stream, the Permittee shall submit updated VOC and HAP calculations in Appendix A for the FT Reactor, utility boiler, and flare (FLA) to the IDEM OAQ Compliance and Enforcement Branch.

Testing Requirements:

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Testing)**	**Pollutant/ Parameter**	**Frequency of Testing**	**Authority**
Three (3) Feedstock Dryers	Baghouses	180*	PM	every 5 years	326 IAC 2-2 326 IAC 6.8-1-2
			PM10 and PM2.5		326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4
	None	180*	NOx	every 5 years	326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4
Three (3) Feedstock Storage and Handling	Baghouse	180*	PM	every 5 years	326 IAC 2-2 326 IAC 6.8-1-2
			PM10 and PM2.5		326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4
Three (3) Ash Silos	Baghouses	180*	PM	every 5 years	326 IAC 2-2 326 IAC 6.8-1-2
			PM10 and PM2.5		326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4
Three (3) Bed Media Silos	Baghouses	180*	PM	every 5 years	326 IAC 2-2 326 IAC 6.8-1-2
			PM10 and PM2.5		326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4
Three (3) Pulse Combustors	SCR System	180*	NOx	every 5 years	326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4
FT Reactor	Utility Boiler	180*	VOC	every 5 years	326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4 326 IAC 8-1-6
Utility Boiler	SCR System	180*	NOx	every 5 years	326 IAC 2-2 326 IAC 2-3 326 IAC 2-8-4
	Oxidation Catalyst		CO		
*No later than 180 days after startup of the emission unit.					

Continuous Emissions Monitoring System (CEMS) Requirements:

Control	**Type of Continuous Monitor (Pollutant Monitored)**	**Applicable Rule or Authority**
Selective Catalytic Reduction (SCR) System - Utility Boiler	CEMS (NOx)	326 IAC 3-5 326 IAC 2-8-5(a)(1),(4) 40 CFR 60 (NSPS)

(b) The Compliance Monitoring Requirements applicable to this source are as follows:

Emission Unit/Control Device	Type of Parametric Monitoring	Frequency	Range or Specification
Pulse Combustors/Selective Catalytic Reduction (SCR) System	Pressure Drop	Daily	Within normal range of 6.0 to 14.0 inches of water, unless a different upper or lower value is established in the most recent compliant stack test
	3-hour average inlet duct temperature	Continuous	At or above the value established in the most recent compliant stack test.
	1-hour average ammonia injection rate	Continuous	At or above the value established in the most recent compliant stack test.
Utility Boiler/Selective Catalytic Reduction (SCR) System*	Ammonia flow rate	Four (4) times per hour	Within normal range from startup until stack test results are available, then within the normal range established in the most recent compliant stack test
	Inlet duct temperature	Four (4) times per hour	Within normal range from startup until stack test results are available, then within the normal range established in the most recent compliant stack test
Utility Boiler/Oxidation Catalyst	3-hour average oxidizer temperature monitoring	Daily	At or above 425°F from startup until stack test results are available, then at or above the value established in the most recent compliant stack test
	Duct pressure or fan amperage monitoring	Daily	Within normal range from startup (or permit issuance) until stack test results are available, then within the normal range established in the most recent compliant stack test
FT Reactor Flare (FLA)	Presence of flame	Continuous	Presence of flame
Truck and Railcar Loadout Flare (LOAD)	Presence of flame	Continuous	Presence of flame
Baghouses/Stacks (SV1, SV2, SV3, and SV4)	Visible emission notations	Daily	Verify whether emissions are normal or abnormal
*Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS.			

These monitoring conditions are necessary because the SCR system for the pulse combustors and utility boiler must operate properly to assure compliance with 326 IAC 2-2 (PSD), 326 IAC 2-3 (Emission Offset), and 326 IAC 2-8-4 (FESOP).

These monitoring conditions are necessary because the oxidation catalyst for the utility boiler must operate properly to assure compliance with 326 IAC 2-2 (PSD), 326 IAC 2-3 (Emission Offset), 326 IAC 2-8-4 (FESOP), and 326 IAC 8-1-6 (VOC BACT).

These monitoring conditions are necessary because the flares for the gasifier trains and the truck and railcar loadout system must operate properly to assure compliance with 326 IAC 6.8 (Particulate Emission Limitations for Lake County).

These monitoring conditions are necessary because the stacks (SV1, SV2, SV3, and SV4) for the feedstock storage, feedstock dryers, ash silos, bed media silos must operate properly to assure compliance with 326 IAC 2-2 (PSD), 326 IAC 2-3 (Emission Offset), 326 IAC 2-8-4 (FESOP), and 326 IAC 6.8 (Particulate Emission Limitations for Lake County).

Conclusion and Recommendation

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 April 30, 2021. Additional information was received on August 11, 2021, August 30, 2021, and September 3, 2021.

The construction and operation of this source shall be subject to the conditions of the attached proposed New Source Construction and FESOP No. F089-44042-00660. The staff recommends to the Commissioner that the New Source Construction and FESOP be approved.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Andrew Belt, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-3217 or (800) 451-6027, and ask for Andrew Belt or (317) 232-3217.

(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 Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
PTE Summary

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Uncontrolled Potential to Emit (tons/yr)									
Emissions Unit	**PM**	**PM10**	**PM2.5 ***	**SO_2**	**NOx**	**VOC**	**CO**	**H_2S**	**Total HAPs****
Feedstock Storage and Handling	810.93	810.93	810.93	-	-	-	-	-	-
Feedstock Dryers	314.96	314.96	314.96	0.24	12.11	2.18	14.94	-	0.75
Silo Emissions	28.74	28.74	28.74	-	-	-	-	-	-
Pulse Combustors	7.40	7.40	7.40	0.58	88.56	5.52	40.87	-	1.84
Sulfur Removal Unit Vent	-	-	-	-	-	-	-	5.23	-
FT Reactor	-	-	-	-	-	1,345.13	-	-	-
Utility Boiler	8.94	8.94	8.94	1.75	45.10	5.01	46.35	-	2.32
Storage Tanks	-	-	-	-	-	10.16	-	-	-
Fire Pump Engine	0.03	0.03	0.03	8.15E-04	0.66	0.25	0.57	-	3.97E-03
Emergency Generator	0.33	0.33	0.33	0.01	10.60	0.71	5.79	-	0.04
Cooling Tower	0.69	0.69	0.69	-	-	-	-	-	-
Wastewater Treatment System	-	-	-	-	-	18.62	-	-	-
Flare	2.20	2.20	2.20	11.07	3.35	21.49	14.91	-	0.06
Truck and Railcar Loadout System & Flare	1.38E-03	4.31E-03	4.31E-03	3.09E-04	0.05	0.43	0.05	-	0.02
Hydrocracker Heater	0.32	0.32	0.32	0.02	4.17	0.23	3.50	-	0.08
Fractionator Heater	0.32	0.32	0.32	0.02	4.17	0.23	3.50	-	0.08
Product Stripper Heater	0.12	0.12	0.12	0.01	1.59	0.09	1.33	-	0.03
Total Excluding Fugitives	**1,174.98**	**1,174.98**	**1,174.98**	**13.72**	**170.35**	**1,410.04**	**131.82**	**5.23**	**-- ****
Fugitive Emissions									
Paved Roads	7.94	1.59	0.39	-	-	-	-	-	-
Slag Handling Activities	*0.04*	*0.02*	*2.96E-03*	-	-	-	-	-	-
Component Leaks	-	-	-	-	-	*19.06*	-	-	0.15
Total Fugitives	*7.98*	*1.61*	*0.39*	*0.00*	*0.00*	*19.06*	*0.00*	*0.00*	*0.15*
Total Including Fugitives	**1,182.96**	**1,176.59**	**1,175.37**	**13.72**	**170.35**	**1,429.10**	**131.82**	**5.23**	**-- ****
								Source-Wide Total HAPs:	**5.36**

** PM2.5 listed is direct PM2.5*
***Fugitive HAP emissions are always included in the source-wide emissions*

Potential to Emit after Issuance (tons/yr)									
Emissions Unit	**PM**	**PM10**	**PM2.5 ***	**SO_2**	**NOx**	**VOC**	**CO**	**H_2S**	**Total HAPs****
Feedstock Storage and Handling	168.98	37.19	18.66	-	-	-	-	-	-
FT Reactor	-	-	-	-	-	48.12	-	-	-
Feedstock Dryers	15.75	15.75	15.75	0.24	41.91		14.94	-	0.75
Pulse Combustors	7.40	7.40	7.40	0.58			40.87	-	1.84
Utility Boiler	8.94	8.94	8.94	1.75			4.63	-	2.32
Flare	2.20	2.20	2.20	11.07			14.91	-	0.06
Hydrocracker Heater	0.32	0.32	0.32	0.02			3.50	-	0.08
Fractionator Heater	0.32	0.32	0.32	0.02			3.50	-	0.08
Product Stripper Heater	0.12	0.12	0.12	0.01			1.33	-	0.03
Wastewater Treatment System	-	-	-	-	-		-	-	-
Storage Tanks	-	-	-	-	-		-	-	-
Fire Pump Engine	0.03	0.03	0.03	0.00	0.13	0.05	0.57	-	3.97E-03
Emergency Generator	0.33	0.33	0.33	0.01	2.12	0.14	5.79	-	0.04
Silo Emissions	1.44	1.44	1.44	-	-	-	-	-	-
Sulfur Removal Unit Vent	-	-	-	-	-	-	-	5.23	-
Cooling Tower	0.69	0.69	0.69	-	-	-	-	-	-
Truck and Railcar Loadout System & Flare	1.38E-03	4.31E-03	4.31E-03	3.09E-04	0.05	0.43	0.05	-	0.02
Total Excluding Fugitives	**206.52**	**74.73**	**56.20**	**13.72**	**44.21**	**48.73**	**90.10**	**5.23**	**-- ****
Fugitive Emissions									
Paved Roads	*7.94*	*1.59*	*0.39*	-	-	-	-	-	-
Slag Handling Activities	*0.04*	*0.02*	*0.00*	-	-	-	-	-	-
Component Leaks	-	-	-	-	-	*19.06*	-	-	*0.15*
Total Fugitives	*7.98*	*1.61*	*0.39*	*0.00*	*0.00*	*19.06*	*0.00*	*0.00*	*0.15*
Total Including Fugitives	**214.50**	**76.33**	**56.59**	**13.72**	**44.21**	**67.80**	**90.10**	**5.23**	**-- ****
								Source-Wide Total HAPs:	**5.36**

** PM2.5 listed is direct PM2.5*
***Fugitive HAP emissions are always included in the source-wide emissions*
Note: The gray shaded cells indicate where limits are included.

Appendix A: Emission Calculations
Feedstock Storage & Handling and Feedstock Dryer Baghouse Emissions

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameter	Unit	Baghouse for Feedstock Storage and Transfer to Feed Bins [a]	Baghouses for Feedstock Drying [b,c]
Exhaust Gas Flow Rate	ft^3/min	216,000	71,993
Outlet PM Loading	grains/ft^3	0.005	0.0058
Annual Operation	hrs/yr	8760	8760
Hourly PM Emissions (Uncontrolled)	lb/hr	185.14	71.91
Annual PM Emissions (Uncontrolled)	tons/yr	810.93	314.96
Individual Hourly PM Emissions (Controlled)	lb/hr	3.09	1.20
Individual Annual PM Emissions (Controlled)	tons/yr	13.52	5.25
Total Hourly PM Emissions (Controlled)	lb/hr	9.26	3.60
Total Annual PM Emissions (Controlled)	tons/yr	40.55	15.75
Individual Hourly PM Emissions (Limited)	lb/hr	12.86	1.20
Individual Annual PM Emissions (Limited)	tons/yr	56.33	5.25
Total Hourly PM Emissions (Limited)	lb/hr	38.58	3.60
Total Annual PM Emissions (Limited)	tons/yr	168.98	15.75
Individual Hourly PM10 Emissions (Limited)	lb/hr	2.83	1.20
Individual Annual PM10 Emissions (Limited)	tons/yr	12.40	5.25
Total Hourly PM10 Emissions (Limited)	lb/hr	8.49	3.60
Total Annual PM10 Emissions (Limited)	tons/yr	37.19	15.75
Individual Hourly PM2.5 Emissions (Limited)	lb/hr	1.42	1.20
Individual Annual PM2.5 Emissions (Limited)	tons/yr	6.22	5.25
Total Hourly PM2.5 Emissions (Limited)	lb/hr	4.26	3.60
Total Annual PM2.5 Emissions (Limited)	tons/yr	18.66	15.75

Notes:
[a] Data provided by Fulcrum Centerpoint
[b] Outlet dust loading based on input load of 0.78 lb/Mmbtu per Vendor (Earth Care)
Exhaust flowrate = 71,993 x 3 = 215,979 ACFM
[c] Baghouse Removal Efficiency based on Baghouse Vendor guarantee of clean gas value <10mg/m3 and inlet load of 0.78 lb/mmbtu
Removal Efficiency = 95.0%
Assume PM=PM10=PM2.5 unless otherwise noted

Appendix A: Emission Calculations
Feedstock Dryer

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)[c]	Number of Dryers	Emission Factors	Units	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
Nitrogen Oxides (NO_X)[a]	30.73	3	0.030	lb/mmbtu	1,020	8,760	2.77	12.11
Carbon Monoxide (CO)[a]	30.73	3	0.037	lb/mmbtu	1,020	8,760	3.41	14.94
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)[b]	30.73	3	0.78	lb/mmbtu	1,020	8,760	71.91	314.96
Sulfur Dioxide (SO2)[d]	30.73	3	0.6	lb/MMscf	1,020	8,760	0.05	0.24
Volatile Organic Compounds (VOC)[d]	30.73	3	5.5	lb/MMscf	1,020	8,760	0.50	2.18

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factors (lb/MMscf) [d]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
2-Methylnaphthalene	91-57-6	92.19	2.40E-05	1,020	8,760	2.17E-06	9.50E-06
3-Methylchloranthrene	56-49-5	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
7,12-Dimethylbenz(a)anthracene	57-97-6	92.19	1.60E-05	1,020	8,760	1.45E-06	6.33E-06
Acenaphthene	83-32-9	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Acenaphthylene	203-96-8	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Anthracene	120-12-7	92.19	2.40E-06	1,020	8,760	2.17E-07	9.50E-07
Benz(a)anthracene	56-55-3	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Benzene	71-43-2	92.19	2.10E-03	1,020	8,760	1.90E-04	8.31E-04
Benzo(a)pyrene	50-32-8	92.19	1.20E-06	1,020	8,760	1.08E-07	4.75E-07
Benzo(b)fluoranthene	205-99-2	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Benzo(g,h,i)perylene	191-24-2	92.19	1.20E-06	1,020	8,760	1.08E-07	4.75E-07
Benzo(k)fluoranthene	207-08-9	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Chrysene	218-01-9	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Dibenz(a,h)anthracene	53-70-3	92.19	1.20E-06	1,020	8,760	1.08E-07	4.75E-07
Dichlorobenzene	25321-22-6	92.19	1.20E-03	1,020	8,760	1.08E-04	4.75E-04
Fluoranthene	206-44-0	92.19	3.00E-06	1,020	8,760	2.71E-07	1.19E-06
Fluorene	86-73-7	92.19	2.80E-06	1,020	8,760	2.53E-07	1.11E-06
Formaldehyde	50-00-0	92.19	7.50E-02	1,020	8,760	6.78E-03	0.03
Hexane	110-54-3	92.19	1.80E+00	1,020	8,760	1.63E-01	0.71
Indeno(1,2,3-cd)pyrene	193-39-5	92.19	1.80E-06	1,020	8,760	1.63E-07	7.13E-07
Naphthalene	91-20-3	92.19	6.10E-04	1,020	8,760	5.51E-05	2.41E-04
Phenanthrene	85-01-8	92.19	1.70E-05	1,020	8,760	1.54E-06	6.73E-06
Pyrene	129-00-0	92.19	5.00E-06	1,020	8,760	4.52E-07	1.98E-06
Toluene	108-88-3	92.19	3.40E-03	1,020	8,760	3.07E-04	1.35E-03
Arsenic	7440-38-2	92.19	2.00E-04	1,020	8,760	1.81E-05	7.92E-05
Beryllium	7440-41-7	92.19	1.20E-05	1,020	8,760	1.08E-06	4.75E-06
Cadmium	7440-43-9	92.19	1.10E-03	1,020	8,760	9.94E-05	4.35E-04
Chromium	7440-47-3	92.19	1.40E-03	1,020	8,760	1.27E-04	5.54E-04
Cobalt	7440-48-4	92.19	8.40E-05	1,020	8,760	7.59E-06	3.33E-05
Manganese	7439-96-5	92.19	3.80E-04	1,020	8,760	3.43E-05	1.50E-04
Mercury	7439-97-6	92.19	2.60E-04	1,020	8,760	2.35E-05	1.03E-04
Nickel	7440-02-0	92.19	2.10E-03	1,020	8,760	1.90E-04	8.31E-04
Selenium	7782-49-2	92.19	2.40E-05	1,020	8,760	2.17E-06	9.50E-06
Total HAPs						0.17	0.75

Notes:
[a] Emission Factors for NOx and CO by Vendor (Earth Care) for Low NOx burners.
[b] Emission Factors for PM and SO2 by Vendor (Earth Care)
[c] Heat input of 30.73 Mmbtu/hr per burner by Vendor (Earth Care)
[d] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2

Appendix A: Emission Calculations
Silos and Hoppers

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameter	Units	Bed Media Silo Baghouses [c]	Ash Silo Baghouses [c]
Exhaust Gas Flow Rate [a]	ft^3/min	3,828	3,828
Outlet PM Loading [b]	grains/ft^3	0.005	0.005
Silo/Hopper Loading Rate	tons/hr	0.23	N/A
Annual Operation[d]	hrs/yr	8,760	8,760
Total Hourly PM/PM10/PM2.5 Emissions (Uncontrolled)	lb/hr	3.28	3.28
Total Annual PM/PM10/PM2.5 Emissions (Uncontrolled)	tons/yr	14.37	14.37
Individual Hourly PM/PM10/PM2.5 Emissions (Controlled/Limited)	lb/hr	0.055	0.055
Individual Annual PM/PM10/PM2.5 Emissions (Controlled/Limited)	tons/yr	0.24	0.24
Total Hourly PM/PM10/PM2.5 Emissions (Controlled/Limited)	lb/hr	0.16	0.16
Total Annual PM/PM10/PM2.5 Emissions (Controlled/Limited)	tons/yr	0.72	0.72

Notes:
[a] Data provided by Fulcrum Centerpoint
[b] Outlet dust loading based on expected levels for fabric filter dust collectors provided by Fulcrum Centerpoint
[c] Emission estimated based on the exhaust gas flow rates of the silo top baghouses.
Control efficiency is estimated at 95%

Appendix A: Emission Calculations
Slag Handling Activities

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Activity	Type of Operation	Hourly Throughput (ton/hr)	Annual Operating Hours (hrs/year)	Annual Throughput (tons/year)	M - Moisture Content [a] (%)	U - Wind Speed [b] (mph)	Uncontrolled Emission Factor [c]			Hourly Emissions [c]			Annual Emissions [c]		
							PM (lb/ton)	PM_{10} (lb/ton)	$PM_{2.5}$ (lb/ton)	PM (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)
Slag Handling	Batch Drop	0.525	8,760	4,599	0.92	10.3	0.01797	0.00850	0.00129	0.0094	0.0045	0.0007	0.0413	0.0195	0.0030

Notes:
[a] Based on Table 13.4.2-1 of AP-42 (for iron and steel production slag material).
[b] Average hourly wind speed for Chicago, Illinois
[c] Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 2006) Section 13.2.4:
E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM, 0.35 for PM_{10}, and .053 for $PM_{2.5}$.

Appendix A: Emission Calculations
Pulse Combustors

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Number of Units	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
		lb/MMscf [a]	lb/MMBtu [b]					
Nitrogen Oxides (NOx)[c]	75.6	--	0.089	3	1020	8760	20.22	88.56
Carbon Monoxide (CO)[c]	75.6	--	0.041	3	1020	8760	9.33	40.87
Particulate Matters (PM/PM10/PM2.5)	75.6	7.60	--	3	1020	8760	1.69	7.40
Sulfur Dioxide (SO2)	75.6	0.60	--	3	1020	8760	0.13	0.58
Volatile Organic Compounds (VOC)	75.6	--	0.00556	3	1020	8760	1.26	5.52

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [d]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
2-Methylnaphthalene	91-57-6	226.8	2.40E-05	1020	8760	5.34E-06	2.34E-05
3-Methylchloranthrene	56-49-5	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
7,12-Dimethylbenz(a)anthracene	57-97-6	226.8	1.60E-05	1020	8760	3.56E-06	1.56E-05
Acenaphthene	83-32-9	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Acenaphthylene	203-96-8	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Anthracene	120-12-7	226.8	2.40E-06	1020	8760	5.34E-07	2.34E-06
Benz(a)anthracene	56-55-3	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Benzene	71-43-2	226.8	2.10E-03	1020	8760	4.67E-04	2.05E-03
Benzo(a)pyrene	50-32-8	226.8	1.20E-06	1020	8760	2.67E-07	1.17E-06
Benzo(b)fluoranthene	205-99-2	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Benzo(g,h,i)perylene	191-24-2	226.8	1.20E-06	1020	8760	2.67E-07	1.17E-06
Benzo(k)fluoranthene	207-08-9	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Chrysene	218-01-9	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Dibenz(a,h)anthracene	53-70-3	226.8	1.20E-06	1020	8760	2.67E-07	1.17E-06
Dichlorobenzene	25321-22-6	226.8	1.20E-03	1020	8760	2.67E-04	1.17E-03
Fluoranthene	206-44-0	226.8	3.00E-06	1020	8760	6.67E-07	2.92E-06
Fluorene	86-73-7	226.8	2.80E-06	1020	8760	6.23E-07	2.73E-06
Formaldehyde	50-00-0	226.8	7.50E-02	1020	8760	1.67E-02	0.07
Hexane	110-54-3	226.8	1.80E+00	1020	8760	4.00E-01	1.75
Indeno(1,2,3-cd)pyrene	193-39-5	226.8	1.80E-06	1020	8760	4.00E-07	1.75E-06
Naphthalene	91-20-3	226.8	6.10E-04	1020	8760	1.36E-04	5.94E-04
Phenanthrene	85-01-8	226.8	1.70E-05	1020	8760	3.78E-06	1.66E-05
Pyrene	129-00-0	226.8	5.00E-06	1020	8760	1.11E-06	4.87E-06
Toluene	108-88-3	226.8	3.40E-03	1020	8760	7.56E-04	3.31E-03
Arsenic	7440-38-2	226.8	2.00E-04	1020	8760	4.45E-05	1.95E-04
Beryllium	7440-41-7	226.8	1.20E-05	1020	8760	2.67E-06	1.17E-05
Cadmium	7440-43-9	226.8	1.10E-03	1020	8760	2.45E-04	1.07E-03
Chromium	7440-47-3	226.8	1.40E-03	1020	8760	3.11E-04	1.36E-03
Cobalt	7440-48-4	226.8	8.40E-05	1020	8760	1.87E-05	8.18E-05
Manganese	7439-96-5	226.8	3.80E-04	1020	8760	8.45E-05	3.70E-04
Mercury	7439-97-6	226.8	2.60E-04	1020	8760	5.78E-05	2.53E-04
Nickel	7440-02-0	226.8	2.10E-03	1020	8760	4.67E-04	2.05E-03
Selenium	7782-49-2	226.8	2.40E-05	1020	8760	5.34E-06	2.34E-05
Total HAPs						0.42	1.84

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors are based on Vendor provided lb/hr values for 75.6 MMBtu/hr design
[c] Emissions based on SCR Control efficiency of 90% for NOx
[d] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4

Appendix A: Emission Calculations
Natural Gas and Purge Gas Combustion
MMBTU/HR >100
Fischer Tropsch (FT) Synthesis Reactor and Utility Boiler

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

1. Utility Boiler

Regulated Air Pollutants	Natural Gas Only Firing					Combination Natural Gas and Purge Gas Firing											Any Fuel	
						Natural Gas Firing			Purge Gas Firing				Total					
	Emission Factor [a]	Heat Input [b]	Maximum Emissions	Operating Hours	Unlimited Emissions	Emission Factor [a]	Heat Input [d]	Maximum Emissions	Emission Factor [c]	Heat Input [d]	Control Efficiency[g]	Maximum Emissions	Hourly Emissions	Operating Hours	Unlimited Emissions	Controlled Emissions	Unlimited Emissions	Controlled Emissions
	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)	(hrs/yr)	(tpy)	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)	(lb/MMBtu)	(MMBtu/hr)	(%)	(lb/hr)	(lb/hr)	(hrs/yr)	(tpy)	(tpy)	(tpy)	(tpy)
Nitrogen Oxides (NOx)[f]	0.036	286.0	10.30	8,760	45.10	0.036	249.20	8.97	0.036	36.80	83.00	1.32	10.30	8,760	45.10	7.67	45.10	7.67
Carbon Monoxide (CO)[g]	0.037	286.0	10.58	8,760	46.35	0.037	249.20	9.22	0.037	36.80	90.00	1.36	10.58	8,760	46.35	4.63	46.35	4.63
Particulate (PM/PM10/PM2.5)	0.007	286.0	2.00	8,760	8.77	0.007	249.20	1.74	0.008	36.80	0.00	0.30	2.04	8,760	8.94	8.94	8.94	8.94
Sulfur Dioxide (SO2)	0.001	286.0	0.40	8,760	1.75	0.001	249.20	0.35	--	36.80	0.00	3.68E-04	0.35	8,760	1.53	1.53	1.75	1.75
Volatile Organic Compounds (VOC)	0.004	286.0	1.14	8,760	5.01	0.004	249.20	1.00	0.004	36.80	96.00	0.15	1.14	8,760	5.01	4.39	5.01	4.39
Sulfuric Acid Mist (SAM)	--	286.0	0.06	8,760	0.27	0.002	249.20	0.43	--	36.80	0.00	5.64E-05	0.43	8,760	1.87	1.87	1.87	1.87

[a] Natural gas-firing emissions factors -
NOx, CO, PM, VOC = Vendor (Cleaver Brooks) Estimate
SO2 = Vendor (Victory Energy) Estimate (based on 1 grain/100 SCF sulfur in fuel, assuming 100% conversion of fuel sulfur to SO2)
SAM = Assuming 10% of SO2 converts into SAM
[b] Heat input based on boiler design data from vendor (Cleaver Brooks) for a 200,000 lb/hr steam flow.
[c] Purge gas-firing emissions factors -
NOx and CO = Vendor (Cleaver Brooks) Estimate (using Natural Gas)
PM = 8.2 lb/10^6 scf CH4 (Table 2.4-5, AP-42 Section 2.4)
SO2 : Based on H2S content of 0.0352 ppmw
VOC = 55,300.00 ppmw
0.004 lb/MMBtu - Vendor (Cleaver Brooks) Estimate
Vendor assured the 0.004 lb/MMBtu emission factor could be achieved for both combusting natural gas and purge gas.
SAM - Assuming 10% of SO2 converts into SAM
[d] Maximum heat input from purge gas and the remaining is from natural gas.
Purge gas heat content = 6,612.26 Btu/lb
Purge gas flow = 5,553.48 lb/hr
Purge gas MW = 22.23 lb/lb-mol
Purge gas volume flow = 96,338.15 scf/hr
Purge gas density = 0.0576 lb/scf
Purge gas heat content = 381.17 Btu/scf
[e] VOC in purge gas assumed to be 96% destroyed during Purge gas combustion in burner (based on AP-42 Section 2.4)
[f] SCR control efficicency of 83% for NOx
[g] Oxidation catalyst system control efficiency of 90% for CO

2. FT Reactor

FT Reactor Purge Gas PTE		
Purge Flow	5,553.48	lb/hr
	2.78	tph
	24,324.23	tpy
VOC Content	55,300.00	ppmw
VOC %	5.530%	
VOC Total	1,345.13	tpy
Control Efficiency	99.60%	
Controlled VOC Total	5.38	tpy

Purge Gas Cost Savings		
Hourly Heat Input	36.72	MMBtu/hr
Annual Heat Input	321,667.20	MMBtu/yr
Convert to Therms	3,217,440.97	therm/yr
Nipsco Natural Gas Price	$ 0.51	$/therm
Total Annual Savings	$ 1,640,894.89	$/yr

Appendix A: Emission Calculations
Natural Gas and Purge Gas Combustion
MMBTU/HR >100
Utility Boiler

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Hazardous Air Pollutants	CAS Number	Natural Gas Only Firing					Combination Natural Gas and Purge Gas Firing									Maximum Annual Emissions Any Fuel (tpy)
							Natural Gas Firing			Purge Gas Firing						
		Emission Factor [a] (lb/MMScf)	Heat Input [b] (MMBtu/hr)	Maximum Emissions [c] (lb/hr)	Operating Hours (hrs/yr)	Annual Emissions (tpy)	Emission Factor (lb/MMScf)	Heat Input [d] (MMBtu/hr)	Maximum Emissions [c] (lb/hr)	Emission Factor [e] (lb/MMscf)	Heat Input [d] (MMBtu/hr)	Maximum Emissions[c] (lb/hr)	Total Hourly Emissions (lb/hr)	Operating Hours (hrs/yr)	Annual Emissions (tpy)	
2-Methylnaphthalene	91-57-6	2.40E-05	286.0	6.73E-06	8,760	2.95E-05	2.40E-05	249.2	5.86E-06	-	36.8	-	5.86E-06	8,760	2.57E-05	2.95E-05
3-Methylchloranthrene	56-49-5	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	286.0	4.49E-06	8,760	1.96E-05	1.60E-05	249.2	3.91E-06	-	36.8	-	3.91E-06	8,760	1.71E-05	1.96E-05
Acenaphthene	83-32-9	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Acenaphthylene	203-96-8	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Anthracene	120-12-7	2.40E-06	286.0	6.73E-07	8,760	2.95E-06	2.40E-06	249.2	5.86E-07	-	36.8	-	5.86E-07	8,760	2.57E-06	2.95E-06
Benz(a)anthracene	56-55-3	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Benzene	71-43-2	2.10E-03	286.0	5.89E-04	8,760	2.58E-03	2.10E-03	249.2	5.13E-04	-	36.8	-	5.13E-04	8,760	2.25E-03	2.58E-03
Benzo(a)pyrene	50-32-8	1.20E-06	286.0	3.36E-07	8,760	1.47E-06	1.20E-06	249.2	2.93E-07	-	36.8	-	2.93E-07	8,760	1.28E-06	1.47E-06
Benzo(b)fluoranthene	205-99-2	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Benzo(g,h,i)perylene	191-24-2	1.20E-06	286.0	3.36E-07	8,760	1.47E-06	1.20E-06	249.2	2.93E-07	-	36.8	-	2.93E-07	8,760	1.28E-06	1.47E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Chrysene	218-01-9	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Dibenz(a,h)anthracene	53-70-3	1.20E-06	286.0	3.36E-07	8,760	1.47E-06	1.20E-06	249.2	2.93E-07	-	36.8	-	2.93E-07	8,760	1.28E-06	1.47E-06
Dichlorobenzene	25321-22-6	1.20E-03	286.0	3.36E-04	8,760	1.47E-03	1.20E-03	249.2	2.93E-04	-	36.8	-	2.93E-04	8,760	1.28E-03	1.47E-03
Fluoranthene	206-44-0	3.00E-06	286.0	8.41E-07	8,760	3.68E-06	3.00E-06	249.2	7.33E-07	-	36.8	-	7.33E-07	8,760	3.21E-06	3.68E-06
Fluorene	86-73-7	2.80E-06	286.0	7.85E-07	8,760	3.44E-06	2.80E-06	249.2	6.84E-07	-	36.8	-	6.84E-07	8,760	3.00E-06	3.44E-06
Formaldehyde	50-00-0	7.50E-02	286.0	2.10E-02	8,760	9.21E-02	7.50E-02	249.2	1.83E-02	-	36.8	-	1.83E-02	8,760	8.03E-02	0.09
Hexane	110-54-3	1.80E+00	286.0	5.05E-01	8,760	2.21E+00	1.80E+00	249.2	4.40E-01	-	36.8	-	4.40E-01	8,760	1.93E+00	2.21
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	286.0	5.05E-07	8,760	2.21E-06	1.80E-06	249.2	4.40E-07	-	36.8	-	4.40E-07	8,760	1.93E-06	2.21E-06
Naphthalene	91-20-3	6.10E-04	286.0	1.71E-04	8,760	7.49E-04	6.10E-04	249.2	1.49E-04	-	36.8	-	1.49E-04	8,760	6.53E-04	7.49E-04
Phenanthrene	85-01-8	1.70E-05	286.0	4.77E-06	8,760	2.09E-05	1.70E-05	249.2	4.15E-06	-	36.8	-	4.15E-06	8,760	1.82E-05	2.09E-05
Pyrene	129-00-0	5.00E-06	286.0	1.40E-06	8,760	6.14E-06	5.00E-06	249.2	1.22E-06	-	36.8	-	1.22E-06	8,760	5.35E-06	6.14E-06
Toluene	108-88-3	3.40E-03	286.0	9.53E-04	8,760	4.18E-03	3.40E-03	249.2	8.31E-04	-	36.8	-	8.31E-04	8,760	3.64E-03	4.18E-03
Arsenic	7440-38-2	2.00E-04	286.0	5.61E-05	8,760	2.46E-04	2.00E-04	249.2	4.89E-05	-	36.8	-	4.89E-05	8,760	2.14E-04	2.46E-04
Beryllium	7440-41-7	1.20E-05	286.0	3.36E-06	8,760	1.47E-05	1.20E-05	249.2	2.93E-06	-	36.8	-	2.93E-06	8,760	1.28E-05	1.47E-05
Cadmium	7440-43-9	1.10E-03	286.0	3.08E-04	8,760	1.35E-03	1.10E-03	249.2	2.69E-04	-	36.8	-	2.69E-04	8,760	1.18E-03	1.35E-03
Chromium	7440-47-3	1.40E-03	286.0	3.93E-04	8,760	1.72E-03	1.40E-03	249.2	3.42E-04	-	36.8	-	3.42E-04	8,760	1.50E-03	1.72E-03
Cobalt	7440-48-4	8.40E-05	286.0	2.36E-05	8,760	1.03E-04	8.40E-05	249.2	2.05E-05	-	36.8	-	2.05E-05	8,760	8.99E-05	1.03E-04
Manganese	7439-96-5	3.80E-04	286.0	1.07E-04	8,760	4.67E-04	3.80E-04	249.2	9.28E-05	-	36.8	-	9.28E-05	8,760	4.07E-04	4.67E-04
Mercury	7439-97-6	2.60E-04	286.0	7.29E-05	8,760	3.19E-04	2.60E-04	249.2	6.35E-05	-	36.8	-	6.35E-05	8,760	2.78E-04	3.19E-04
Nickel	7440-02-0	2.10E-03	286.0	5.89E-04	8,760	2.58E-03	2.10E-03	249.2	5.13E-04	-	36.8	-	5.13E-04	8,760	2.25E-03	2.58E-03
Selenium	7782-49-2	2.40E-05	286.0	6.73E-06	8,760	2.95E-05	2.40E-05	249.2	5.86E-06	-	36.8	-	5.86E-06	8,760	2.57E-05	2.95E-05
Methanol	67-56-1	--	--	--	--	--	--	249.2	-	3.53E-02	36.8	1.30E-06	1.30E-06	8,760	5.69E-06	5.69E-06
POH	--	--	--	--	--	--	--	249.2	-	1.80E-02	36.8	6.61E-07	6.61E-07	8,760	2.89E-06	2.89E-06
Total HAPs																2.32

Notes:
[a] Natural gas-firing emissions factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[b] Heat input based on boiler design data.
[c] For Emission estimation, used heat content of natural gas and purge gas as 1020 and 381.6 Btu/scf respectively
[d] Maximum heat input from purge gas and the remaining is from natural gas.
[e] Purge Gas-firing emissions factors were estimated based on mole fraction of the compounds (Fulcrum Centerpoint design data).

Appendix A: Emission Calculations
Sulfur Removal Unit Vent

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameters	Units	Value
Total Exhaust Gas Flow Rate [a]	lbmol/hr	3,514
H2S concentration in exhaust gas [b]	ppmv	10
No. of moles of H2S	lbmol/hr	0.035
Annual Operating Hours	hrs/yr	8760
Hourly H2S Emissions [c]	lb/hr	1.19
Annual H2S Emissions	tons/yr	5.23

Notes:
[a] Exhaust gas flow rate based on Fulcrum Centerpoint design data (CO2 vent from Aspen Model)
[b] Vendor guaranteed concentration in exhaust gas
[c] Hourly H2S Emissions (lb/hr) = Molar Flow (lbmol/hr) X Molecular weight of H2S (34 lbs/lbmol)

Appendix A: Emission Calculations
Flare

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameters [a]	Pilot Gas	Startup (SU)		Shutdown		
		Flare SU Stream After Scrubber	Flare SU Stream After Amine System	Flare SD Stream Before Compressor (Low Pressure)	Flare SD Stream After Compressor (High Pressure)	Flare SD Stream - Draining & Inspecting (Naptha)
Gas flow rate to Flare (scfm)	1.915	--	-	--	--	--
Annual gas flow rate to Flare (MMscf/yr)	1.01	--	-	--	--	--
Gas heating value (Btu/ft3, HHV)	1020	239.00	304.00			
Gas heating value (Btu/lb, HHV)	--	--	-	4,347.66	6,612.26	20,587.00
Total annual flaring event	Continuous	6.00	1.00	12.00	12.00	4.00
Duration of flaring event (hrs)	--	12.00	12.00	0.25	2.00	12.00
Gas flow during flaring event (lb/hr)	--	248,252.00	106,371.00	4,583.00	27,903.00	102.76
Gas molecular weight (lb/lb-mol)	--	21.17	11.26	21.17	43.30	125.00
Hourly heat input (MMBtu/hr)	0.12	1,080.59	1,107.04	19.93	184.50	2.12
Annual hours of operation	8760	72.00	12.00	3.00	24.00	48.00
Annual heat input (MMBtu/yr)	1026.7	77,802.14	13,284.54	59.78	4,428.04	101.55

Regulated Air Pollutants	Pilot Gas Combustion		
	Emission Factor [b]	Units	Annual Emisisons (tons/yr)
Carbon Monoxide (CO)	84	lb/MMscf	0.042
Nitrogen Oxides (NOx)	100	lb/MMscf	0.050
Particulate Matter (PM)	7.6	lb/MMscf	0.004
Particulate Matter (PM10)	7.6	lb/MMscf	0.004
Particulate Matter (PM2.5)	7.6	lb/MMscf	0.004
Volatile Organic Compounds (VOC)	5.5	lb/MMscf	0.003
Sulfur Dioxide (SO2)	0.6	lb/MMscf	0.000

Regulated Air Pollutants	Flare SU - after scrubber'		Flare SU - after Amine		Flare SD - Low Pressure		Flare SD -High Pressure'		Flare SD - Draining & Inpecting		Total Annual Emisisons from SU & SD events (tons/yr)
	Emission Factor(lb/MMBtu) [c]	Annual Emisisons from SU after scrubber (tons/yr)	Emission Factor (lb/MMBtu)	Annual Emisisons from SU Events (tons/yr)	Emission Factor (lb/MMBtu) [c]	Annual Emisisons from SU Events (tons/yr)	Emission Factor (lb/MMBtu) [c]	Annual Emisisons from SU after scrubber (tons/yr)	Emission Factor (lb/MMBtu) [c]	Annual Emisisons from SU Events (tons/yr)	
Carbon Monoxide (CO)	0.31	12.059	0.310	2.059	0.310	0.686	0.31	0.009	0.310	0.016	14.87
Nitrogen Oxides (NOx)	0.068	2.645	0.068	0.452	0.068	0.151	0.068	0.002	0.068	0.003	3.30
Particulate Matter (PM)	0.0478	1.859	0.038	0.249	0.038	0.083	0.038	0.001	0.038	0.002	2.20
Particulate Matter (PM10)	0.0478	1.859	0.038	0.249	0.038	0.083	0.038	0.001	0.038	0.002	2.20
Particulate Matter (PM2.5)	0.0478	1.859	0.038	0.249	0.038	0.083	0.038	0.001	0.038	0.002	2.20
Volatile Organic Compounds (VOC)	0.14	5.446	0.140	0.930	0.140	0.310	0.14	0.004	0.140	0.007	6.70
Sulfur Dioxide (SO2)	0.2683	10.438	0.003	0.018	0.278	0.614	0.0000	0.000	0.000	0.000	11.07

FLARE POTENTIAL TO EMIT CALCULATIONS

Parameters [a]	Pilot Gas	Startup (SU)		Shutdown		
		Flare SU Stream After Scrubber	Flare SU Stream After Amine System	Flare SD Stream Before Compressor (Low Pressure)	Flare SD Stream After Compressor (High Pressure)	Flare SD Stream - Draining & Inspecting (Naptha)
Gas flow rate to Flare (scfm)	1.915	--	-	--	--	--
Annual gas flow rate to Flare (MMscf/yr)	1.0	--	-	--	--	--
Gas heating value (Btu/ft3, HHV)	1020.0	239.00	304.00			0.00
Gas heating value (Btu/lb, HHV)	--	--	-	4,347.66	6,612.26	20,587.00
Total annual flaring event	Continuous	6.00	1.00	12.00	12.00	4.00
Duration of flaring event (hrs)	--	12.00	12.00	0.25	2.00	12.00
Gas flow during flaring event (lb/hr)	--	248,252.00	106,371.00	4,583.00	27,903.00	102.76
Gas molecular weight (lb/lb-mol)	--	21.17	11.26	21.17	43.30	125.00
Hourly heat input (MMBtu/hr)	0.1	1,080.59	1,107.04	19.93	184.50	2.12
Annual hours of operation	8760.0	72.00	12.00	3.00	24.00	48.00
Annual heat input (MMBtu/yr)	1026.7	77,802.14	13,284.54	59.78	4,428.04	101.55
VOC wt%		0.000%	0.030%	0.000%	0.030%	5.5%
VOC flow during flaring event (lb/hr)		0.00	32.08	0.00	8.41	5.68
VOC flow during flaring event (lb/yr)		0.00	384.94	0.00	201.96	272.85
VOC flow during flaring event (ton/yr)		0.00	0.19	0.00	0.10	0.14

Total Flare PTE	**21.49**

Notes:
[a] Data based on design specifications provided by Fulcrum Centerpoint.
[b] Natural gas firing emissions factors based on Chapter 1.4, AP-42.
[c] CO, NOx, and VOC emissions factors based on Chapter 13.5, AP-42. PM emissions factors based on Fulcrum Centerpoint estimate of soot content of 40 ug/L in a lightly smoking flare.
SO2 emissions estimated based on Fulcrum Centerpoint design data.

The number of flare events differ between the different processes because there are scenarios where small portions of the plant may require de-pressurization, but the entire plant will not require a full start-up to bring operations back online.
The Btu/lb amounts change between suction and discharge because of the syngas clean up happening in this stage. The labels of "before" and "after" the compressor are mainly to designate the low vs. high pressure portions of the facility. Additional syngas clean-up steps occur between these two "vent to flare" locations. The main one impacting the gas heating value is CO2 removal. CO2 is removed from the syngas between these two stream locations and therefore, the downstream syngas without CO2 has a higher heating value.

Appendix A: Emission Calculations
Flare - HAP Emissions

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameters [a]	Pilot Gas	Startup		Shutdown		
		Flare SU after scrubber	Flare SU after amine	Flare SD - Low Pressure	Flare SD -High Pressure	Flare SD - Draining & Inspecting
Gas flow rate to Flare (scfm)	1.92	--	-	--	--	--
Annual gas flow rate to Flare (MMscf/yr)	1.01	--	-	--	--	--
Gas heating value (Btu/ft3, HHV)	1,020	239	304			
Gas heating value (Btu/lb, HHV)	--	--	-	4,347.66	6,612.26	20,587.00
Total annual flaring event	Continuous	6.00	6.00	12.00	12.00	4.00
Duration of flaring event (hrs)	--	12.00	12.00	0.25	2.00	12.00
Gas flow during flaring event (lb/hr)	--	248,252	106,371	4,583	55,806	1,292.86
Gas molecular weight (lb/lb-mol)	--	21.17	11.26	21.17	43.30	125.00
Hourly heat input (MMBtu/hr)	0.12	1,080.59	1,107.04	19.93	369.00	26.62
Annual hours of operation	8,760	72.00	72.00	3.00	24.00	48.00
Annual heat input (MMBtu/yr)	1,026.65	77,802.14	79,707.21	59.78	8,856.09	1,277.57

Hazardous Air Pollutants	Pilot Gas Combustion			Syngas Combustion during SU and SD			
	Emission Factor [b]	Units	Annual Emisisons (tons/yr)	Concentration [c] (ppmw)	Annual Emisisons from SU Events (tons/yr)	Annual Emisisons from SD Events (tons/yr)	Total Annual Emisisons (tons/yr)
2-Methylnaphthalene	2.40E-05	lb/MMscf	1.21E-08	--	--	--	1.21E-08
3-Methylchloranthrene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	8.05E-09	--	--	--	8.05E-09
Acenaphthene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Acenaphthylene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Anthracene	2.40E-06	lb/MMscf	1.21E-09	--	--	--	1.21E-09
Benz(a)anthracene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Benzene	2.10E-03	lb/MMscf	1.06E-06	--	--	--	1.06E-06
Benzo(a)pyrene	1.20E-06	lb/MMscf	6.04E-10	--	--	--	6.04E-10
Benzo(b)fluoranthene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	6.04E-10	--	--	--	6.04E-10
Benzo(k)fluoranthene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Chrysene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Dibenz(a,h)anthracene	1.20E-06	lb/MMscf	6.04E-10	--	--	--	6.04E-10
Dichlorobenzene	1.20E-03	lb/MMscf	6.04E-07	--	--	--	6.04E-07
Fluoranthene	3.00E-06	lb/MMscf	1.51E-09	--	--	--	1.51E-09
Fluorene	2.80E-06	lb/MMscf	1.41E-09	--	--	--	1.41E-09
Formaldehyde	7.50E-02	lb/MMscf	3.77E-05	--	--	--	3.77E-05
Hexane	1.80E+00	lb/MMscf	9.06E-04	--	--	--	9.06E-04
Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	9.06E-10	--	--	--	9.06E-10
Naphthalene	6.10E-04	lb/MMscf	3.07E-07	--	--	--	3.07E-07
Phenanthrene	1.70E-05	lb/MMscf	8.56E-09	--	--	--	8.56E-09
Pyrene	5.00E-06	lb/MMscf	2.52E-09	--	--	--	2.52E-09
Toluene	3.40E-03	lb/MMscf	1.71E-06	--	--	--	1.71E-06
Arsenic	2.00E-04	lb/MMscf	1.01E-07	--	--	--	1.01E-07
Beryllium	1.20E-05	lb/MMscf	6.04E-09	--	--	--	6.04E-09
Cadmium	1.10E-03	lb/MMscf	5.54E-07	--	--	--	5.54E-07
Chromium	1.40E-03	lb/MMscf	7.05E-07	--	--	--	7.05E-07
Cobalt	8.40E-05	lb/MMscf	4.23E-08	--	--	--	4.23E-08
Manganese	3.80E-04	lb/MMscf	1.91E-07	--	--	--	1.91E-07
Mercury	2.60E-04	lb/MMscf	1.31E-07	--	--	--	1.31E-07
Nickel	2.10E-03	lb/MMscf	1.06E-06	--	--	--	1.06E-06
Selenium	2.40E-05	lb/MMscf	1.21E-08	--	--	--	1.21E-08
Total HAPs from Syngas flaring [d]	--	--	--	4.02	5.13E-02	2.84E-03	5.41E-02
Total HAPS							**0.06**

[a] Data based on design specifications provided by Fulcrum Centerpoint.
[b] Natural gas-firing HAP emissions factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Concentrations based on Aspen model, Fulcrum Centerpoint data
[d] Assuming 100% of VOC emissions as HAPs. VOC concentration obtained from Fulcrum Centerpoint design data.

Appendix A: Emission Calculations
Hydrocracker Heater

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
		lb/MMscf [a]	lb/MMBtu				
Nitrogen Oxides (NOx)	9.7	100.0	--	1020	8,760	0.95	4.17
Carbon Monoxide (CO)	9.7	84.0	--	1020	8,760	0.80	3.50
Particulate (PM/PM10/PM2.5)	9.7	7.60	--	1020	8,760	0.07	0.32
Sulfur Dioxide (SO2)	9.7	0.60	--	1020	8,760	0.01	0.02
Volatile Organic Compounds (VOC)	9.7	5.50	--	1020	8,760	0.05	0.23

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [b]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
2-Methylnaphthalene	91-57-6	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
3-Methylchloranthrene	56-49-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	9.7	1.60E-05	1020	8,760	1.52E-07	6.66E-07
Acenaphthene	83-32-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Acenaphthylene	203-96-8	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Anthracene	120-12-7	9.7	2.40E-06	1020	8,760	2.28E-08	1.00E-07
Benz(a)anthracene	56-55-3	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzene	71-43-2	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Benzo(a)pyrene	50-32-8	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(b)fluoranthene	205-99-2	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzo(g,h,i)perylene	191-24-2	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(k)fluoranthene	207-08-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Chrysene	218-01-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Dibenz(a,h)anthracene	53-70-3	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Dichlorobenzene	25321-22-6	9.7	1.20E-03	1020	8,760	1.14E-05	5.00E-05
Fluoranthene	206-44-0	9.7	3.00E-06	1020	8,760	2.85E-08	1.25E-07
Fluorene	86-73-7	9.7	2.80E-06	1020	8,760	2.66E-08	1.17E-07
Formaldehyde	50-00-0	9.7	7.50E-02	1020	8,760	7.13E-04	3.12E-03
Hexane	110-54-3	9.7	1.80E+00	1020	8,760	1.71E-02	0.07
Indeno(1,2,3-cd)pyrene	193-39-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Naphthalene	91-20-3	9.7	6.10E-04	1020	8,760	5.80E-06	2.54E-05
Phenanthrene	85-01-8	9.7	1.70E-05	1020	8,760	1.62E-07	7.08E-07
Pyrene	129-00-0	9.7	5.00E-06	1020	8,760	4.75E-08	2.08E-07
Toluene	108-88-3	9.7	3.40E-03	1020	8,760	3.23E-05	1.42E-04
Arsenic	7440-38-2	9.7	2.00E-04	1020	8,760	1.90E-06	8.33E-06
Beryllium	7440-41-7	9.7	1.20E-05	1020	8,760	1.14E-07	5.00E-07
Cadmium	7440-43-9	9.7	1.10E-03	1020	8,760	1.05E-05	4.58E-05
Chromium	7440-47-3	9.7	1.40E-03	1020	8,760	1.33E-05	5.83E-05
Cobalt	7440-48-4	9.7	8.40E-05	1020	8,760	7.99E-07	3.50E-06
Manganese	7439-96-5	9.7	3.80E-04	1020	8,760	3.61E-06	1.58E-05
Mercury	7439-97-6	9.7	2.60E-04	1020	8,760	2.47E-06	1.08E-05
Nickel	7440-02-0	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Selenium	7782-49-2	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
Total HAPs						0.02	0.08

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Emission Factors from 40 CFR 98 Table C-1

Appendix A: Emission Calculations
Fractionator Heater

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
		lb/MMscf [a]	lb/MMBtu				
Nitrogen Oxides (NOx)	9.7	100.0	--	1020	8,760	0.95	4.17
Carbon Monoxide (CO)	9.7	84.0	--	1020	8,760	0.80	3.50
Particulate (PM/PM10/PM2.5)	9.7	7.60	--	1020	8,760	0.07	0.32
Sulfur Dioxide (SO2)	9.7	0.60	--	1020	8,760	0.01	0.02
Volatile Organic Compounds (VOC)	9.7	5.50	--	1020	8,760	0.05	0.23

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [b]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
2-Methylnaphthalene	91-57-6	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
3-Methylchloranthrene	56-49-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	9.7	1.60E-05	1020	8,760	1.52E-07	6.66E-07
Acenaphthene	83-32-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Acenaphthylene	203-96-8	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Anthracene	120-12-7	9.7	2.40E-06	1020	8,760	2.28E-08	1.00E-07
Benz(a)anthracene	56-55-3	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzene	71-43-2	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Benzo(a)pyrene	50-32-8	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(b)fluoranthene	205-99-2	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Benzo(g,h,i)perylene	191-24-2	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Benzo(k)fluoranthene	207-08-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Chrysene	218-01-9	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Dibenz(a,h)anthracene	53-70-3	9.7	1.20E-06	1020	8,760	1.14E-08	5.00E-08
Dichlorobenzene	25321-22-6	9.7	1.20E-03	1020	8,760	1.14E-05	5.00E-05
Fluoranthene	206-44-0	9.7	3.00E-06	1020	8,760	2.85E-08	1.25E-07
Fluorene	86-73-7	9.7	2.80E-06	1020	8,760	2.66E-08	1.17E-07
Formaldehyde	50-00-0	9.7	7.50E-02	1020	8,760	7.13E-04	3.12E-03
Hexane	110-54-3	9.7	1.80E+00	1020	8,760	1.71E-02	0.07
Indeno(1,2,3-cd)pyrene	193-39-5	9.7	1.80E-06	1020	8,760	1.71E-08	7.50E-08
Naphthalene	91-20-3	9.7	6.10E-04	1020	8,760	5.80E-06	2.54E-05
Phenanthrene	85-01-8	9.7	1.70E-05	1020	8,760	1.62E-07	7.08E-07
Pyrene	129-00-0	9.7	5.00E-06	1020	8,760	4.75E-08	2.08E-07
Toluene	108-88-3	9.7	3.40E-03	1020	8,760	3.23E-05	1.42E-04
Arsenic	7440-38-2	9.7	2.00E-04	1020	8,760	1.90E-06	8.33E-06
Beryllium	7440-41-7	9.7	1.20E-05	1020	8,760	1.14E-07	5.00E-07
Cadmium	7440-43-9	9.7	1.10E-03	1020	8,760	1.05E-05	4.58E-05
Chromium	7440-47-3	9.7	1.40E-03	1020	8,760	1.33E-05	5.83E-05
Cobalt	7440-48-4	9.7	8.40E-05	1020	8,760	7.99E-07	3.50E-06
Manganese	7439-96-5	9.7	3.80E-04	1020	8,760	3.61E-06	1.58E-05
Mercury	7439-97-6	9.7	2.60E-04	1020	8,760	2.47E-06	1.08E-05
Nickel	7440-02-0	9.7	2.10E-03	1020	8,760	2.00E-05	8.75E-05
Selenium	7782-49-2	9.7	2.40E-05	1020	8,760	2.28E-07	1.00E-06
Total HAPs						0.02	0.08

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Emission Factors from 40 CFR 98 Table C-1

Appendix A: Emission Calculations
Product Stripper Heater

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Criteria Pollutant	Burner Heat Input (MMBtu/hr)	Emission Factors		Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
		lb/MMscf [a]	lb/MMBtu				
Nitrogen Oxides (NOx)	3.7	100.0	--	1020	8760	0.36	1.59
Carbon Monoxide (CO)	3.7	84.0	--	1020	8760	0.30	1.33
Particulate (PM/PM10/PM2.5)	3.7	7.60	--	1020	8760	0.03	0.12
Sulfur Dioxide (SO2)	3.7	0.60	--	1020	8760	0.00	0.01
Volatile Organic Compounds (VOC)	3.7	5.5	--	1020	8760	0.02	0.09

Hazardous Air Pollutants	CAS Number	Burner Heat Input (MMBtu/hr)	Emission Factor (lb/MMscf) [b]	Natural Gas Heat Content (Btu/scf) (HHV)	Annual Operating Hours	Emissions (lb/hr)	Emissions (TPY)
2-Methylnaphthalene	91-57-6	3.7	2.40E-05	1020	8760	8.71E-08	3.81E-07
3-Methylchloranthrene	56-49-5	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	3.7	1.60E-05	1020	8760	5.80E-08	2.54E-07
Acenaphthene	83-32-9	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Acenaphthylene	203-96-8	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Anthracene	120-12-7	3.7	2.40E-06	1020	8760	8.71E-09	3.81E-08
Benz(a)anthracene	56-55-3	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Benzene	71-43-2	3.7	2.10E-03	1020	8760	7.62E-06	3.34E-05
Benzo(a)pyrene	50-32-8	3.7	1.20E-06	1020	8760	4.35E-09	1.91E-08
Benzo(b)fluoranthene	205-99-2	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Benzo(g,h,i)perylene	191-24-2	3.7	1.20E-06	1020	8760	4.35E-09	1.91E-08
Benzo(k)fluoranthene	207-08-9	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Chrysene	218-01-9	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Dibenz(a,h)anthracene	53-70-3	3.7	1.20E-06	1020	8760	4.35E-09	1.91E-08
Dichlorobenzene	25321-22-6	3.7	1.20E-03	1020	8760	4.35E-06	1.91E-05
Fluoranthene	206-44-0	3.7	3.00E-06	1020	8760	1.09E-08	4.77E-08
Fluorene	86-73-7	3.7	2.80E-06	1020	8760	1.02E-08	4.45E-08
Formaldehyde	50-00-0	3.7	7.50E-02	1020	8760	2.72E-04	1.19E-03
Hexane	110-54-3	3.7	1.80E+00	1020	8760	6.53E-03	0.03
Indeno(1,2,3-cd)pyrene	193-39-5	3.7	1.80E-06	1020	8760	6.53E-09	2.86E-08
Naphthalene	91-20-3	3.7	6.10E-04	1020	8760	2.21E-06	9.69E-06
Phenanthrene	85-01-8	3.7	1.70E-05	1020	8760	6.17E-08	2.70E-07
Pyrene	129-00-0	3.7	5.00E-06	1020	8760	1.81E-08	7.94E-08
Toluene	108-88-3	3.7	3.40E-03	1020	8760	1.23E-05	5.40E-05
Arsenic	7440-38-2	3.7	2.00E-04	1020	8760	7.25E-07	3.18E-06
Beryllium	7440-41-7	3.7	1.20E-05	1020	8760	4.35E-08	1.91E-07
Cadmium	7440-43-9	3.7	1.10E-03	1020	8760	3.99E-06	1.75E-05
Chromium	7440-47-3	3.7	1.40E-03	1020	8760	5.08E-06	2.22E-05
Cobalt	7440-48-4	3.7	8.40E-05	1020	8760	3.05E-07	1.33E-06
Manganese	7439-96-5	3.7	3.80E-04	1020	8760	1.38E-06	6.04E-06
Mercury	7439-97-6	3.7	2.60E-04	1020	8760	9.43E-07	4.13E-06
Nickel	7440-02-0	3.7	2.10E-03	1020	8760	7.62E-06	3.34E-05
Selenium	7782-49-2	3.7	2.40E-05	1020	8760	8.71E-08	3.81E-07
Total HAPs						0.01	0.03

Notes:
[a] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-1 and 1.4-2
[b] Emission Factors based on AP-42 Chapter 1.4, Tables 1.4-3 and 1.4-4
[c] Emission Factors from 40 CFR 98 Table C-1

Appendix A: Emission Calculations
VOC Emissions from Storage Tanks

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Storage Liquid	Chemical Profile used in Tanks 4.09d	Shell Height (ft)	Shell Diameter (ft)	Liquid Height (ft)	Average Liquid Height (ft)	Reid Vapor Pressure (psia)	Actual Vapor Pressure (psia)	Temperature (F)	Roof Color	Storage Capacity (gallons)	Tank Type	Liquid Bulk Temperature (° F)	Net Throughput (gallons)	Turnovers	Uncontrolled Annual VOC Emissions (lbs) [a]	Uncontrolled Annual VOC Emissions (Tons)
Product Storage Tank (SPK)[b]	Jet Kerosene	40	50	35	16	0.008	0.008	100	white	587,000	Vertical Fixed Roof Tank	100	11,695,408	20	320.76	0.16
Product Storage Tank (SPK)	Jet Kerosene	40	50	35	16	0.008	0.008	100	white	587,000	Vertical Fixed Roof Tank	100	11,695,408	20	320.76	0.16
Product Storage Tank (SPK)	Jet Kerosene	40	50	35	16	0.008	0.008	100	white	587,000	Vertical Fixed Roof Tank	100	11,695,408	20	320.76	0.16
Off-Spec Product Storage Tank (SPK)	Jet Kerosene	30	35	25	16	0.008	0.008	100	white	216,000	Vertical Fixed Roof Tank	100	100,000	0.46	32.34	0.02
Solvent Sump Drum (Amine)[c]	Amine	32	21	18	15	0.02	7.7	100	white	45,000	Vertical Fixed Roof Tank	100	45,000	1	2,016.70	1.01
FT Liquid Storage (HFTL)	Crude Oil	26	22	23	16	0.58	6.7	100	white	73,000	External Floating Roof	300	146,000	2	3,270.87	1.64
FT Liquid Storage (MFTL)	Gasoline RVP7	26	25	23	16	6.59	3.7	100	white	94,300	External Floating Roof	110	188,600	2	14,041.90	7.02
Diesel Storage Tanks (x4) for Emergency Generator and Fire Pump Engine	Distillate Oil 2	11	4	10	6	0.4	0.0056	55	gray/light	4,000	Vertical Fixed Roof Tank	51	6,120	2	1.10	5.49E-04
															Total:	10.16

Notes:
[a] Emissions are calculated using EPA Tanks 4.09d
[b] Assumed SPK as closer to Jet Kerosene while calculating emissions from Tanks 4.09d
[c] Assumed diethylamine as the amine used in the process

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Fire Pump Engine

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	15.3
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	2.8
Engine size (hp)[1]	399
Engine size (kW)[1]	298
Daily hours of operation	4
Annual hours of operation	500
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Engine Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	399	0.2	g/kW-hr	1	0.13	0.03
PM_{10}	-	399	0.2	g/kW-hr	1	0.13	0.03
$PM_{2.5}$ [3]	-	399	0.2	g/kW-hr	1	0.13	0.03
NO_X	-	399	4	g/kW-hr	1	2.62	0.66
CO	630-08-0	399	3.5	g/kW-hr	1	2.30	0.57
SO_2 [4]	7446-09-5	399	0.0015	% S	1	0.0033	8.15E-04
VOC	-	399	0.00247	lb/hp-hr	1	0.99	0.25

Hazardous Air Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	399	3.91E-05	lb/MMBtu	1	1.09E-04	2.73E-05
Acenaphthene	83-32-9	399	1.42E-06	lb/MMBtu	1	3.97E-06	9.92E-07
Acenaphthylene	203-96-8	399	5.06E-06	lb/MMBtu	1	1.41E-05	3.53E-06
Acrolein	107-02-8	399	9.25E-05	lb/MMBtu	1	2.58E-04	6.46E-05
Anthracene	120-12-7	399	1.87E-06	lb/MMBtu	1	5.22E-06	1.31E-06
Benzo(a)anthracene	56-55-3	399	1.68E-06	lb/MMBtu	1	4.69E-06	1.17E-06
Benzene	71-43-2	399	9.33E-04	lb/MMBtu	1	2.61E-03	6.51E-04
Benzo(a)pyrene	50-32-8	399	1.88E-07	lb/MMBtu	1	5.25E-07	1.31E-07
Benzo(b)fluoranthene	205-99-2	399	9.91E-08	lb/MMBtu	1	2.77E-07	6.92E-08
Benzo(g,h,I)perylene	191-24-2	399	4.89E-07	lb/MMBtu	1	1.37E-06	3.41E-07
Benzo(k)fluoranthene	207-08-9	399	1.55E-07	lb/MMBtu	1	4.33E-07	1.08E-07
Chrysene	218-01-9	399	3.53E-07	lb/MMBtu	1	9.86E-07	2.46E-07
Dibenz(a,h)anthracene	53-70-3	399	5.83E-07	lb/MMBtu	1	1.63E-06	4.07E-07
Fluoranthene	206-44-0	399	7.61E-06	lb/MMBtu	1	2.13E-05	5.31E-06
Fluorene	86-73-7	399	2.92E-05	lb/MMBtu	1	8.16E-05	2.04E-05
Formaldehyde	50-00-0	399	1.18E-03	lb/MMBtu	1	3.30E-03	8.24E-04
Indeno(1,2,3-cd)pyrene	193-39-5	399	3.75E-07	lb/MMBtu	1	1.05E-06	2.62E-07
Naphthalene	91-20-3	399	8.48E-05	lb/MMBtu	1	2.37E-04	5.92E-05
Phenanthrene	85-01-8	399	2.94E-05	lb/MMBtu	1	8.21E-05	2.05E-05
Propylene	115-07-1	399	2.58E-03	lb/MMBtu	1	7.21E-03	1.80E-03
Pyrene	129-00-0	399	4.78E-06	lb/MMBtu	1	1.34E-05	3.34E-06
Toluene	108-88-3	399	4.09E-04	lb/MMBtu	1	1.14E-03	2.86E-04
Xylene	1330-20-7	399	2.85E-04	lb/MMBtu	1	7.96E-04	1.99E-04
					Totals:	0.02	3.97E-03

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 4 of 40 CFR 60 Subpart IIII. Other pollutants are based on AP 42, Chapter 3.3, Table 3.3-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

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Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Fire Pump Engine

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	15.3
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	2.8
Engine size (hp)[1]	399
Engine size (kW)[1]	298
Daily hours of operation	4
Annual hours of operation	100
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Engine Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	399	0.2	g/kW-hr	1	0.13	0.01
PM_{10}	-	399	0.2	g/kW-hr	1	0.13	0.01
$PM_{2.5}$ [3]	-	399	0.2	g/kW-hr	1	0.13	0.01
NO_X	-	399	4	g/kW-hr	1	2.62	0.13
CO	630-08-0	399	3.5	g/kW-hr	1	2.30	0.11
SO_2 [4]	7446-09-5	399	0.0015	% S	1	0.0033	1.63E-04
VOC	-	399	0.00247	lb/hp-hr	1	0.99	0.05

Hazardous Air Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	399	3.91E-05	lb/MMBtu	1	1.09E-04	5.46E-06
Acenaphthene	83-32-9	399	1.42E-06	lb/MMBtu	1	3.97E-06	1.98E-07
Acenaphthylene	203-96-8	399	5.06E-06	lb/MMBtu	1	1.41E-05	7.07E-07
Acrolein	107-02-8	399	9.25E-05	lb/MMBtu	1	2.58E-04	1.29E-05
Anthracene	120-12-7	399	1.87E-06	lb/MMBtu	1	5.22E-06	2.61E-07
Benzo(a)anthracene	56-55-3	399	1.68E-06	lb/MMBtu	1	4.69E-06	2.35E-07
Benzene	71-43-2	399	9.33E-04	lb/MMBtu	1	2.61E-03	1.30E-04
Benzo(a)pyrene	50-32-8	399	1.88E-07	lb/MMBtu	1	5.25E-07	2.63E-08
Benzo(b)fluoranthene	205-99-2	399	9.91E-08	lb/MMBtu	1	2.77E-07	1.38E-08
Benzo(g,h,I)perylene	191-24-2	399	4.89E-07	lb/MMBtu	1	1.37E-06	6.83E-08
Benzo(k)fluoranthene	207-08-9	399	1.55E-07	lb/MMBtu	1	4.33E-07	2.16E-08
Chrysene	218-01-9	399	3.53E-07	lb/MMBtu	1	9.86E-07	4.93E-08
Dibenz(a,h)anthracene	53-70-3	399	5.83E-07	lb/MMBtu	1	1.63E-06	8.14E-08
Fluoranthene	206-44-0	399	7.61E-06	lb/MMBtu	1	2.13E-05	1.06E-06
Fluorene	86-73-7	399	2.92E-05	lb/MMBtu	1	8.16E-05	4.08E-06
Formaldehyde	50-00-0	399	1.18E-03	lb/MMBtu	1	3.30E-03	1.65E-04
Indeno(1,2,3-cd)pyrene	193-39-5	399	3.75E-07	lb/MMBtu	1	1.05E-06	5.24E-08
Naphthalene	91-20-3	399	8.48E-05	lb/MMBtu	1	2.37E-04	1.18E-05
Phenanthrene	85-01-8	399	2.94E-05	lb/MMBtu	1	8.21E-05	4.11E-06
Propylene	115-07-1	399	2.58E-03	lb/MMBtu	1	7.21E-03	3.60E-04
Pyrene	129-00-0	399	4.78E-06	lb/MMBtu	1	1.34E-05	6.68E-07
Toluene	108-88-3	399	4.09E-04	lb/MMBtu	1	1.14E-03	5.71E-05
Xylene	1330-20-7	399	2.85E-04	lb/MMBtu	1	7.96E-04	3.98E-05
					Totals:	0.02	7.94E-04

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 4 of 40 CFR 60 Subpart IIII. Other pollutants are based on AP 42, Chapter 3.3, Table 3.3-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

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Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Emergency Generator

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	205.6
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	28.2
Engine size (hp)[1]	4029
Engine size (kW)[1]	3004
Daily hours of operation	4
Annual hours of operation	500
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	4029	0.2	g/kW-hr	1	1.32	0.33
PM_{10}	-	4029	0.2	g/kW-hr	1	1.32	0.33
$PM_{2.5}$ [3]	-	4029	0.2	g/kW-hr	1	1.32	0.33
NO_X	-	4029	6.4	g/kW-hr	1	42.39	10.60
CO	630-08-0	4029	3.5	g/kW-hr	1	23.18	5.79
SO_2 [4]	7446-09-5	4029	0.0015	% S	1	0.0438	0.01
VOC	-	4029	7.05E-04	lb/hp-hr	1	2.84	0.71

Hazardous Air Pollutants	CAS	Engine Size (hp)	Emission Factor [5]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	4029	3.91E-05	lb/MMBtu	1	1.10E-03	2.76E-04
Acenaphthene	83-32-9	4029	1.42E-06	lb/MMBtu	1	4.00E-05	1.00E-05
Acenaphthylene	203-96-8	4029	5.06E-06	lb/MMBtu	1	1.43E-04	3.57E-05
Acrolein	107-02-8	4029	9.25E-05	lb/MMBtu	1	2.61E-03	6.52E-04
Anthracene	120-12-7	4029	1.87E-06	lb/MMBtu	1	5.27E-05	1.32E-05
Benzo(a)anthracene	56-55-3	4029	1.68E-06	lb/MMBtu	1	4.74E-05	1.18E-05
Benzene	71-43-2	4029	9.33E-04	lb/MMBtu	1	2.63E-02	6.58E-03
Benzo(a)pyrene	50-32-8	4029	1.88E-07	lb/MMBtu	1	5.30E-06	1.33E-06
Benzo(b)fluoranthene	205-99-2	4029	9.91E-08	lb/MMBtu	1	2.79E-06	6.99E-07
Benzo(g,h,l)perylene	191-24-2	4029	4.89E-07	lb/MMBtu	1	1.38E-05	3.45E-06
Benzo(k)fluoranthene	207-08-9	4029	1.55E-07	lb/MMBtu	1	4.37E-06	1.09E-06
Chrysene	218-01-9	4029	3.53E-07	lb/MMBtu	1	9.95E-06	2.49E-06
Dibenz(a,h)anthracene	53-70-3	4029	5.83E-07	lb/MMBtu	1	1.64E-05	4.11E-06
Fluoranthene	206-44-0	4029	7.61E-06	lb/MMBtu	1	2.15E-04	5.37E-05
Fluorene	86-73-7	4029	2.92E-05	lb/MMBtu	1	8.23E-04	2.06E-04
Formaldehyde	50-00-0	4029	1.18E-03	lb/MMBtu	1	3.33E-02	8.32E-03
Indeno(1,2,3-cd)pyrene	193-39-5	4029	3.75E-07	lb/MMBtu	1	1.06E-05	2.64E-06
Naphthalene	91-20-3	4029	8.48E-05	lb/MMBtu	1	2.39E-03	5.98E-04
Phenanthrene	85-01-8	4029	2.94E-05	lb/MMBtu	1	8.29E-04	2.07E-04
Propylene	115-07-1	4029	2.58E-03	lb/MMBtu	1	7.28E-02	1.82E-02
Pyrene	129-00-0	4029	4.78E-06	lb/MMBtu	1	1.35E-04	3.37E-05
Toluene	108-88-3	4029	4.09E-04	lb/MMBtu	1	1.15E-02	2.88E-03
Xylene	1330-20-7	4029	2.85E-04	lb/MMBtu	1	8.04E-03	2.01E-03
					Totals:	0.16	0.04

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 1 of 40 CFR 89.112. Other pollutants are based on AP 42, Chapter 3.4, Table 3.4-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

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Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Emergency Generator

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Source	Diesel Engine
Engine fuel consumption (gal/hr)[1]	205.6
Number of identical units operated	1
Engine heat input (MMBtu/hr)[1]	28.2
Engine size (hp)[1]	4029
Engine size (kW)[1]	3004
Daily hours of operation	4
Annual hours of operation	100
Average Break Specific Fuel Consumption (Btu/hp-hr)[1]	7000

Criteria and Regulated Pollutants	CAS	Enginer Size (hp)	Emission Factor [2]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
PM	-	4029	0.2	g/kW-hr	1	1.32	0.07
PM_{10}	-	4029	0.2	g/kW-hr	1	1.32	0.07
$PM_{2.5}$ [3]	-	4029	0.2	g/kW-hr	1	1.32	0.07
NO_X	-	4029	6.4	g/kW-hr	1	42.39	2.12
CO	630-08-0	4029	3.5	g/kW-hr	1	23.18	1.16
SO_2 [4]	7446-09-5	4029	0.0015	% S	1	0.0438	2.19E-03
VOC	-	4029	7.05E-04	lb/hp-hr	1	2.84	0.14

Hazardous Air Pollutants	CAS	Engine Size (hp)	Emission Factor [5]		Number of Identical Units	Total Emissions (lb/hr)	Total Emissions (tons/yr)
			Value	Unit			
1,3-Butadiene	106-99-0	4029	3.91E-05	lb/MMBtu	1	1.10E-03	5.51E-05
Acenaphthene	83-32-9	4029	1.42E-06	lb/MMBtu	1	4.00E-05	2.00E-06
Acenaphthylene	203-96-8	4029	5.06E-06	lb/MMBtu	1	1.43E-04	7.13E-06
Acrolein	107-02-8	4029	9.25E-05	lb/MMBtu	1	2.61E-03	1.30E-04
Anthracene	120-12-7	4029	1.87E-06	lb/MMBtu	1	5.27E-05	2.64E-06
Benzo(a)anthracene	56-55-3	4029	1.68E-06	lb/MMBtu	1	4.74E-05	2.37E-06
Benzene	71-43-2	4029	9.33E-04	lb/MMBtu	1	2.63E-02	1.32E-03
Benzo(a)pyrene	50-32-8	4029	1.88E-07	lb/MMBtu	1	5.30E-06	2.65E-07
Benzo(b)fluoranthene	205-99-2	4029	9.91E-08	lb/MMBtu	1	2.79E-06	1.40E-07
Benzo(g,h,l)perylene	191-24-2	4029	4.89E-07	lb/MMBtu	1	1.38E-05	6.89E-07
Benzo(k)fluoranthene	207-08-9	4029	1.55E-07	lb/MMBtu	1	4.37E-06	2.19E-07
Chrysene	218-01-9	4029	3.53E-07	lb/MMBtu	1	9.95E-06	4.98E-07
Dibenz(a,h)anthracene	53-70-3	4029	5.83E-07	lb/MMBtu	1	1.64E-05	8.22E-07
Fluoranthene	206-44-0	4029	7.61E-06	lb/MMBtu	1	2.15E-04	1.07E-05
Fluorene	86-73-7	4029	2.92E-05	lb/MMBtu	1	8.23E-04	4.12E-05
Formaldehyde	50-00-0	4029	1.18E-03	lb/MMBtu	1	3.33E-02	1.66E-03
Indeno(1,2,3-cd)pyrene	193-39-5	4029	3.75E-07	lb/MMBtu	1	1.06E-05	5.29E-07
Naphthalene	91-20-3	4029	8.48E-05	lb/MMBtu	1	2.39E-03	1.20E-04
Phenanthrene	85-01-8	4029	2.94E-05	lb/MMBtu	1	8.29E-04	4.15E-05
Propylene	115-07-1	4029	2.58E-03	lb/MMBtu	1	7.28E-02	3.64E-03
Pyrene	129-00-0	4029	4.78E-06	lb/MMBtu	1	1.35E-04	6.74E-06
Toluene	108-88-3	4029	4.09E-04	lb/MMBtu	1	1.15E-02	5.77E-04
Xylene	1330-20-7	4029	2.85E-04	lb/MMBtu	1	8.04E-03	4.02E-04
					Totals:	0.16	8.02E-03

Notes:
1. Based on Fulcrum Centerpoint data
2. NOx, CO, and PM emissions factors are based on Table 1 of 40 CFR 89.112. Other pollutants are based on AP 42, Chapter 3.4, Table 3.4-1.
3. $PM_{2.5}$ assumed equal to PM_{10}
4. Based on ultra-low-sulfur diesel fuel with maximum sulfur content of 0.0015% by weight. Fuel density 7.1 lb/gal.
5. Emission factors based on AP-42, Chapter 3.3, Table 3.3-2.

YDS

Appendix A: Emission Calculations
Cooling Tower

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Parameter [a]	Units	Value
Cooling tower Circulation Rate	gpm	39,930
Cooling tower Circulation Rate	lb/hr	19,973,785
Total Dissolved Solids	ppm	790
Annual hours of Operation	hours	8760
Drift[c]	%	0.001
PM Emissions	lb/hr	0.1578
PM Emissions	TPY	0.6911

Notes:
[a] Data provided by Fulcrum Centerpoint
[b]The TDS assumptions are determined using an estimate of the TDS in incoming process water to the site and three cycles of concentration in the cooling water loop.
[c]The estimate of drift from the cooling tower was taken from the manufacturers' information for high efficiency drift eliminators.
Assume PM=PM10=PM2.5

Appendix A: Emission Calculations
Wastewater Treatment System (WTS)

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

VOC Concentration (mg/L)	Flow (lpm)	VOC Emissions (Mg/yr)	VOC Emissions (tons/yr)
33	1,426	16.89	18.62

Methodology:
VOC Emissions (Mg/yr) = VOC Concentration (mg/L) x Flow (lpm) x 0.000000001 Mg/mg x 60 min/hr x 8,760 hr/yr x f_e
Where:
VOC Concentration = 33 mg/L
Flow = 188,820 lbs/hr = 1,426 lpm
f_e = 0.683 (Weighted Average Value from EPA 453 D-93-056)

Appendix A: Emission Calculations
Truck Loading Loadout Flare

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

1. Flare Stream Emissions

	Molecular Weight, M (lb/lb mole)	Loading Loss, L_L (lb/kgal)	Annual Throughput (kgal/yr)	VOC Input (lb/yr)	Heat Content[1] (MMBtu/lb)	Heat Input (MMBtu/yr)
Synthetic Paraffinic Kerosene (SPK)	130.00	0.025	34,000	848	0.0196	16.60
Total			34,000	848		**16.60**

Notes:
1. Product heat content provided by the source, 8/11/2021.

Methodology
VOC Input (lb/yr) = Loading Loss (lb/kgal) x Annual Throughput (kgal/yr)
Heat Input (MMBtu/yr) = VOC Input (lb/yr) x Heat Content (MMBtu/lb)

A. Criteria Pollutants

	Pollutant						
	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO
Emission Factor[1] (lb/MMBtu)	0.048	0.048	0.048	-[3]	0.068	-[4]	0.31
Potential to Emit (tons/yr)	3.99E-04	3.99E-04	3.99E-04	1.00E-08	5.65E-04		2.57E-03

Notes:
1. NOx and CO emission factors based on Chapter 13.5, AP-42.
2. PM emissions factors based on Fulcrum Centerpoint estimate of soot content of 40 ug/L in a lightly smoking flare.
3. SO2 emissions based on maximum H2S concentration in vent gas and actual vent gas usage. H2S concentration and gas flow of SPK vapor provided by the source.
4. VOC emissions are accounted for in the loading rack PTE.

Methodology
Potential to Emit (tons/yr) = Emission Factor (lb/MMBtu) x Total Heat Input (MMBtu/yr) / 2,000 (lb/ton)
SO2 Potential to Emit (tons/yr) = 0.005 ppm x 2 lb/hr x 1 / 1,000,000

B. Hazardous Air Pollutants

HAP Emissions are accounted for in the loading rack PTE.

Appendix A: Emission Calculations
Truck Loading Loadout Flare

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

2. Pilot Operation

Heat Input Capacity MMBtu/hr	Rating (MMBtu/hr) mmBtu / mmscf	Potential Throughput MMCF/yr
0.1	1020	1.0

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100	5.5	84
					**see below		
Potential Emission in tons/yr	9.79E-04	3.92E-03	3.92E-03	3.09E-04	0.05	2.83E-03	0.04

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.10E-03	1.20E-03	0.08	1.80	3.40E-03	
Potential Emission in tons/yr	1.08E-06	6.18E-07	3.86E-05	9.28E-04	1.75E-06	**9.70E-04**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.00E-04	1.10E-03	1.40E-03	3.80E-04	2.10E-03	
Potential Emission in tons/yr	2.58E-07	5.67E-07	7.21E-07	1.96E-07	1.08E-06	**2.8E-06**
					Total HAPs	**9.72E-04**
					Worst HAP	**9.28E-04**

Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.

3. Potential to Emit After Issuance

	Pollutant						
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO
Flare Steam (tons/yr)	3.99E-04	3.99E-04	3.99E-04	1.00E-08	5.65E-04	-	2.57E-03
Pilot Operations (tons/yr)	9.79E-04	3.92E-03	3.92E-03	3.09E-04	0.05	2.83E-03	0.04
Total	1.38E-03	4.31E-03	4.31E-03	3.09E-04	0.05	2.83E-03	0.05

Appendix A: Emissions Calculations
Truck & Railcar Loadout System

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

1. VOC

Uncontrolled loading loss from AP-42 Chapter 5.2, Eqn. 1.

L_L = 12.46 (SPM / T)
Where L_L = Loading Loss (lb/kgal)
S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of jet kerosene (Jet A) (see Table 7.1-2) = 0.008 psia
M = molecular weight of jet kerosene (Jet A) vapors (see Table 7.1-2) = 130
T = temperature of bulk liquid loaded, °R (°F + 460)

Fuel Type	Saturation Factor	True Vapor Pressure (psia)	Molecular Weight (lb/lb-mole)	Temperature (°R)	L_L Loading Loss (lb/kgal)	Annual Throughput (kgal/yr)	Uncontrolled VOC PTE (ton/yr)	Emission Control Efficiency (%)	Controlled VOC Emissions (ton/yr)	Emissions Limit (lb/kgal)
Synthetic Paraffinic Kerosene (SPK)	1.0	0.008	130	519.67	0.025	34,000	0.42	98%	0.01	4.99E-04
Total							**0.42**		**0.01**	

Methodology
1 kgal = 1,000 gal
Vapor recovery collection efficiency is from AP-42 Chapter 5.2.
Uncontrolled VOC PTE (ton/yr) = Annual throughput (kgal/yr) x loading loss (lb/kgal) x 1 ton / 2000 lb
Controlled VOC PTE (ton/yr) = Uncontrolled VOC PTE (ton/yr) x [1 - (Control Eff x Collection Eff.)]
Emissions Limit (lb/kgal) = L_L (lb/kgal) x (1-Control Efficiency (%)/100)

2. Hazardous Air Pollutants

HAP	HAP/VOC (wt%)	Uncontrolled PTE (tons/yr)
Benzene	0.9	3.82E-03
Cumene	0.1	4.24E-04
Ethylbenzene	0.1	4.24E-04
n-Hexane	1.6	6.78E-03
Naphthalene	0.5	2.12E-03
Toluene	1.3	5.51E-03
2,2,4-Trimethylpentane	0.8	3.39E-03
Xylenes	0.5	2.12E-03
Total HAPs		0.02

Notes:

Source: Table 3-2 Gasoline HAP Vapor Profile, Technical Guidance-Stage II Vapor Recovery Systems for Control of Vehicle Refueling Emissions at Gasoline Dispensing Facilities, Vol. I: Chapters, EPA 450/3-91-022a, Nov 1991. The HAP profile is used because emissions from truck loading operations are determined by the vapors from the last product transported, motor gasoline as a worst case for this source.

Uncontrolled HAP PTE (tons/yr) = Uncontrolled VOC PTE (tons/yr) * HAP/VOC (wt%)/100

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

Paved Roads at Industrial Site
The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight Loaded (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	120.0	1.0	120.0	19.0	2280.0	2000	0.379	45.5	16590.9
Vehicle (leaving plant) (one-way trip)	120.0	1.0	120.0	0.0	0.0	2000	0.379	45.5	16590.9
Vehicle (entering plant) (one-way trip)	14.0	1.0	14.0	0.0	0.0	3500	0.663	9.3	3387.3
Vehicle (leaving plant) (one-way trip)	14.0	1.0	14.0	20.0	280.0	3500	0.663	9.3	3387.3
		Totals	**268.0**		**2,560.0**			**109.5**	**39,956.4**

Average Vehicle Weight Per Trip = 9.6 tons/trip
Average Miles Per Trip = 0.41 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	9.6	9.6	9.6	tons = average vehicle weight (provided by source)
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 125 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	0.869	0.174	0.0427	lb/mile
Mitigated Emission Factor, Eext =	0.795	0.159	0.0390	lb/mile
Dust Control Efficiency =	50%	50%	50%	(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)	Mitigated PTE of PM (After Control) (tons/yr)	Mitigated PTE of PM10 (After Control) (tons/yr)	Mitigated PTE of PM2.5 (After Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	6.59	1.32	0.32	3.30	0.66	0.16
Vehicle (leaving plant) (one-way trip)	6.59	1.32	0.32	3.30	0.66	0.16
	1.35	0.27	0.07	0.67	0.13	0.03
	1.35	0.27	0.07	0.67	0.13	0.03
Totals	**15.88**	**3.18**	**0.78**	**7.94**	**1.59**	**0.39**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight Loaded (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (Before Control) (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = [Mitigated PTE (Before Control) (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Fugitive Component Leaks

Company Name: Fulcrum Centerpoint, LLC
Source Address: 6200 Industrial Highway, Gary, Indiana 46406
Permit Number: F089-44042-00660
Reviewer: Andrew Belt

	Petroleum Correlation Constants		Streams 21,26,31,41				Stream 45				Streams 51,60,70,80				ALL STREAMS
Type of Component	Correlation Leak Constant	Exponent	Number of Components [a]	VOC Content (ppmv)	TOC Leak Emission (kg/hr) [b]	VOC Leak (tpy)	Number of Components [a]	VOC Content (ppmv)	TOC Leak Emission (kg/hr) [b]	VOC Leak (tpy)	Number of Components [a]	VOC Content (ppmv)	TOC Leak Emission (kg/hr) [b]	VOC Leak (tpy)	TOTAL (tpy)
Valves in gas service	2.29E-06	0.746	592	2.72E-07	1.71E-08	4.02E-17	224	50.91	9.62E-03	7.24E-03	710	21,093.65	2.73	7.84	**7.85**
Valves in light liquid service	2.29E-06	0.746	39	2.72E-07	1.13E-09	2.65E-18	20	50.91	8.59E-04	6.46E-04	395	21,093.65	1.52	4.36	**4.36**
Pump seals	5.03E-05	0.610	0	2.72E-07	0.00E+00	0.00E+00	8	50.91	4.42E-03	3.33E-03	25	21,093.65	0.55	1.57	**1.57**
Compressor seals[c]	1.36E-05	0.589	0	2.72E-07	0.00E+00	0.00E+00	0	50.91	0.00E+00	0.00E+00	0	21,093.65	0.00	0.00	**0.00**
Pressure relief valves[c]	1.36E-05	0.589	0	2.72E-07	0.00E+00	0.00E+00	0	50.91	0.00E+00	0.00E+00	0	21,093.65	0.00	0.00	**0.00**
Connectors	1.53E-06	0.735	974	2.72E-07	2.22E-08	5.22E-17	380	50.91	1.04E-02	7.85E-03	780	21,093.65	1.80	5.16	**5.17**
Sampling connectors	1.53E-06	0.735	6	2.72E-07	1.37E-10	3.22E-19	3	50.91	8.25E-05	6.20E-05	17	21,093.65	0.04	0.11	**0.11**
			TOC WT %	0.148%	**STREAM TOTAL**	**9.54E-17**	TOC WT %	0.386%	**STREAM TOTAL**	**1.91E-02**	TOC WT %	18.585%	**STREAM TOTAL**	**19.04**	**19.06**
			VOC WT %	3.60E-13			VOC WT %	0.030%			VOC WT %	5.532%			
			VOC%/TOC%	2.44E-10			VOC%/TOC%	7.80%			VOC%/TOC%	29.76%			
			HOURS	8,760			HOURS	8,760			HOURS	8,760			

Total HAP Concentration - Liquid Stream	2.0%
Total HAP Concentration - Gas Stream	0.005%

Type of Component	Liquid Stream HAPs (TPY)	Gas Stream HAPs (TPY)	
Valves in gas service	0.0	0.00038	
Valves in light liquid service	0.09	0	
Pump seals	0.03	0	
Compressor seals	0	0	
Pressure relief valves	0	0	
Connectors	0.03	0.0002	Assume 75% of connectors in gas service/25% in liquid service
Sampling connectors	0.00	0.0000	Assume 75% of sampling connectors in gas service/25% in liquid service
Totals (TPY)	0.15	0.0006	
Total HAPs (TPY) - Liquid and Gas Streams	**0.15**		

Notes:
[a] Number of components based on the process (P&ID) information provided by Fulcrum
[b] Petroleum leak rate/screening value correlations, Table 2-10, EPA Protocol for Equipment Leak Emission Estimates and Table A-4 EPA Correlation Method
[c] Number of compressor seals and pressure relief valves considered as zero since these are vented to flare.

YDS

Indiana Department of Environmental Management
Office of Air Quality

Appendix B
Best Available Control Technology (BACT) Determination

Source Description and Location

Source Name:	**Fulcrum Centerpoint, LLC**
Source Location:	**6200 Industrial Highway, Gary, Indiana 46406**
County:	**Lake (Calumet)**
SIC Code:	**2999 (Products of Petroleum and Coal, Not Elsewhere Classified)**
Operation Permit No.:	**F089-44042-00660**
Permit Reviewer:	**Andrew Belt**

Introduction

On April 30, 2021, Fulcrum Centerpoint, LLC submitted an application to the OAQ for a proposal to construct and operate a new biorefinery. The biorefinery will accept a Processed Engineered Feedstock ("Feedstock") for its gasification, Fischer-Tropsch ("FT") liquids and renewable transportation fuel production process. The ultimate product will be low carbon, renewable transportation fuels. Feedstock for the biorefinery will be produced offsite at separate facilities from Municipal Solid Waste ("MSW"), otherwise destined for landfills in Indiana and Illinois, and then transported to the biorefinery in trucks. The Project will not incinerate or combust MSW, rather it will convert Feedstock into low carbon, renewable transportation fuel.

The one (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, is subject to the requirements of 326 IAC 8-1-6 (BACT) since the potential emissions of volatile organic compounds (VOC) from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor is equal or greater than twenty-five (25) tons per year and the reactor is not otherwise regulated by other provisions of article 8.

Description of Process

Evaluation of the Best Available Control Technology analyses for VOCs was performed for the following emissions unit:

(a) One (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, approved in 2022 for construction, converting syngas into FT liquids (syncrude), with a maximum capacity of 1,650 tons per day. The FT liquids are thermally separated into a heavy FT liquid stream (HFTL) and a medium FT liquid stream (MFTL). The water generated in the FT process is separated from the MFTL and sent to the wastewater treatment facility. The HFTL and MFTL are sent to the HFTL and MFTL intermediate storage tanks. Unreacted syngas is separated from the MFTL and either recycled back to the FT reactor, sent to the POx units for methane reforming or combusted in the utility boiler as purge gas. The HFTL and MFTL hydrocarbon streams are sent from the intermediate storage tanks to the syncrude upgrading section.

Summary of the Best Available Control Technology (BACT) Process

BACT is an emissions 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. Such reductions

are necessary to demonstrate that the emissions remaining after application of BACT will not cause or contribute significantly to air pollution, thereby protecting public health and the environment.

Federal guidance on BACT 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.

The five (5) basic steps of a top-down BACT analysis 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, innovative 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. 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 environmental, energy, and economic impacts specific to the proposed modification. If the analysis determines that the evaluated alternative is not appropriate as BACT due to any of the impacts, then the next most effective is evaluated. This process is repeated until a control alternative is chosen as BACT. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except for the environmental analyses.

Step 4: Evaluate the Most Effective Controls and Document the Results

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

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. BACT must, at a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the permits.

Step 5: Select BACT

The Office of Air Quality (OAQ) makes final BACT determinations by following the five steps identified above.

A summary of the BACT review for the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor is provided below. This BACT determination is based on the following information:

(1) BACT analysis information submitted by Fulcrum Centerpoint, LLC on November 19, 2021;
(2) The EPA RACT/BACT/LAER (RBLC) Clearinghouse; and
(3) State and local air quality permits.

Volatile Organic Compounds (VOC) BACT Analysis

Step 1 – Identify Potential Control Options

Based on the information reviewed for this BACT determination, the following potentially available control technologies were identified for controlling VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor:

(a) Destruction Control Methods
Destruction technologies reduce VOC concentration by high temperature oxidation into carbon dioxide and water vapor. The destruction of organic compounds usually requires temperatures ranging from 1,200°F to 2,000°F for direct thermal incinerators or 600°F to 1,200°F for catalytic systems. Required combustion temperature depends on the chemical composition and desired destruction efficiency. Carbon dioxide and water vapor are the typical products of complete combustion. Turbulent mixing and combustion chamber retention times of 0.5 to 1.0 seconds are needed to obtain high destruction efficiencies.

(1) Incineration in Boilers
Boilers are used as afterburners to incinerate air contaminants. The primary function of a boiler is to supply steam or hot water. Like any other types of controls, boilers require a properly design exhaust system to convey air pollutants effectively from the point of origin to the boiler firebox. Contaminated gases may be introduced into the boiler firebox in two ways:

(i) Through the burner, serving as combustion air, or
(ii) Downstream of the burner, serving as secondary air.

(2) Recuperative Thermal Oxidation
Recuperative thermal incinerators are add-on control devices used to control VOC emissions by introducing solvent-laden fumes to the oxidizer. The recuperative thermal oxidizer is composed of a combustion chamber, a waste gas preheater, and, if appropriate, a secondary energy recovery heat exchanger.

The two types of heat exchangers most used in recuperative thermal oxidizers are plate-to-plate and shell-and tube. Plate-to-plate exchangers offer high efficiency energy recovery at lower cost than shell-and-tube designs and can be built to achieve a variety of efficiencies. However, when gas temperatures exceed 1000°F, shell-and-tube exchangers usually have lower purchase costs. Shell-and-tube exchangers also generally offer better long-term structural reliability than plate-to-plate units.

In a recuperative thermal oxidizer, the waste gas stream is pre-heated by exiting flue gas using a heat exchanger or recuperator. A burner adds additional heat to the air to increase the temperature to a level that will cause incineration of the VOCs in the waste gas stream. The air is then passed through an oxidation chamber where the VOC-laden

waste stream is converted to carbon dioxide and water. The clean air stream then passes through the heat exchanger to preheat incoming waste gases before it is discharged to the atmosphere.

A recuperative thermal oxidizer is appropriate for waste streams with relatively high solvent content and/or consistent pollutant loading. Variation in pollutant loading will require a longer retention time in the oxidizer to properly destroy VOC emissions.

(3) Regenerative Thermal Oxidation
Regenerative thermal oxidizers (RTOs) are add-on control devices used to control VOC emissions by simple reaction of the harmful air pollutants with oxygen and heat. These systems can handle variable and low concentration VOC waste streams.

RTOs use a high-density media such as a ceramic-packed bed still hot from a previous cycle to preheat an incoming VOC-laden waste gas stream. The preheated, partially oxidized gases then enter a combustion chamber where they are heated by auxiliary fuel (typically natural gas) combustion to a final oxidation temperature that is usually 1400 to 1500°F and maintained at this temperature to achieve maximum VOC destruction. The purified, hot gases exit this chamber and are directed to one or more different ceramic-packed beds cooled by an earlier cycle. Heat from the purified gases is absorbed by these beds before the gases are exhausted to the atmosphere. The reheated packed bed then begins a new cycle by heating a new incoming waste gas stream.

The RTO cyclic process leads to high rates of energy recovery (up to 95%). RTOs have higher capital costs due to the high-performance heat exchangers and combustion chambers, but this cost may be offset by the increased auxiliary fuel savings.

(4) Recuperative and Regenerative Catalytic Oxidation
Catalytic incinerators are add-on control devices used to control VOC emissions with a bed of catalyst material that facilitates the oxidation of combustible gases. The catalyst increases the reaction rate and allows for the elimination of VOCs at lower temperatures than thermal incinerators. Catalytic oxidation is appropriate for low-concentration VOC waste streams.

Catalysts can be susceptible to fouling with certain compounds present in waste streams. It may also be necessary to remove particulates prior to catalytic oxidation to ensure proper operation and VOC control.

(5) Flares
Flaring is used to control VOC emissions by piping VOCs to a remote, usually elevated location and burning the VOCs in an open flame in the air using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for nearly complete (>98%) VOC destruction. While flares can provide excellent control of VOC waste gas streams, the equipment can cause safety and operational problems for a production facility. Also, the exhaust stream concentration must remain high enough to sustain combustion.

(b) Reclamation Control Methods
Organic compounds may be reclaimed through one of three methods: adsorption, absorption, or condensation. In general, the organic compounds are separated from the emission stream and reclaimed for reuse or disposal. Depending on the nature of the contaminant and the inlet concentration of the emission stream, recovery technologies can approach efficiencies of 98%.

(1) Adsorption
Adsorption is a surface phenomenon where attraction between carbon and VOC molecules binds the pollutants to the surface of carbon. Both the VOCs and carbon are

chemically intact after adsorption. Then, the VOCs can be removed (desorbed) from the carbon bed for reclamation or destruction.

Adsorption can be used for relatively low VOC exhaust streams. Pollutants present in the gas streams can reduce adsorber efficiency, increase pressure drop, and eventually plug the carbon bed. Adsorption is best suited for exhaust gas streams containing primarily VOCs, as other pollutant loadings can plug the carbon bed.

(2) Absorption
Absorption is a unit operation where components of a gas phase mixture (pollutants) are selectively transferred to a relatively nonvolatile liquid, usually water. Sometimes, organic liquids like mineral oil or nonvolatile hydrocarbons are suitable absorption solvents. Absorption is commonly used to recover products or purify gas streams that have high concentrations of organic compounds. Absorption processes are typically used to recover products or purity gas streams with high concentrations of organic compounds such as in the ethanol production and soybean oil refinery industries.

(3) Condensers
Condensation is the separation of VOCs from an emission stream through a phase change, by increasing the system pressure or more commonly, lowering the system temperature below the dew point of the VOC vapor. When condensers are used for air pollution control, they usually operate at the pressure of the emission stream, and typically require a refrigeration unit to obtain the temperature necessary to condense the VOCs from the emission stream. These systems are frequently used prior to other control devices (e.g., oxidizers or absorbers) to remove components that may be corrosive or damaging to other parts of the system. Condensers are generally used as control devices for treating emission streams with high VOC concentrations (usually >5,000 ppmv).

Step 2 – Eliminate Technically Infeasible Control Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor. The control technologies listed in the previous section are discussed and evaluated below for their technical feasibility.

(a) Recuperative Thermal Oxidation – Technically Feasible
Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of recuperative thermal oxidation is a technically feasible option for the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor at this source. Recuperative thermal oxidation typically needs VOC inlet concentrations of at least 1500 to 3000 ppm to perform acceptably without requiring significant quantities of supplemental fuel to sustain combustion chamber temperatures.

(b) Regenerative Thermal Oxidation – Technically Feasible
Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of regenerative thermal oxidation is a technically feasible option for the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor at this source. RTOs are appropriate for variable and lower concentration VOC gas streams. RTOs have also been used as effective VOC emissions control for similar production processes.

(c) Recuperative and Regenerative Catalytic Oxidation – Technically Feasible
Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of catalytic oxidation is a technically feasible option for the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor at this source. These systems can handle low concentration VOC waste streams and gas flow rates of 700 to 75,000 scfm. The gas stream flow rate is 33,200 acfm.

(d) Flares – Technically Feasible
Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is a technically feasible option for the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor at this source. The only time purge gas would vent to the flare would be during a boiler malfunction. The process would likely also need to be shutdown, and, at which time, the process would no longer produce purge gas.

(e) Adsorption – Not Feasible
Carbon adsorption is not technically feasible for the control of VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, because a prohibitively large-sized carbon bed is required.

(f) Absorption – Not Feasible
Carbon absorption is not technically feasible for the control of VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor. The primary VOC constituent emitted from the FT reactor is purge gas. Because of the chemical makeup of the purge gas, there is a lack of suitable solvents to control VOC emissions.

(g) Condensers – Not Feasible
Condensers are not technically feasible for the control of VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor. Extremely low temperatures are required for condensation.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control options for controlling VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor are ranked below by control efficiency:

(a) Thermal Oxidizer – 98% - 99.9% VOC control

(b) Utility Boiler – 98% VOC control

(c) Flare – 98% VOC control

(d) Catalytic Oxidizer – 95% VOC control

Step 4 – Evaluate the Most Effective Controls and Document Results

RBLC

The U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database was reviewed to identify control requirements and limitations for facilities with similar to the biorefinery. Table 1 below includes a brief summary of search results obtained from the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database.

(1) The U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database search results are based on the following criteria:

(A) SIC Codes 1321 (Natural Gas Liquids), 2911 (Petroleum Refining), 2999 (Products of Petroleum and Coal, Not Elsewhere Classified), 4922 (Natural Gas Transmission), and 4925 (Mixed, Manufactured, or Liquefied Petroleum Gas Production);

(B) Pollutant name - Volatile Organic Compounds;

(C) Facilities listed since 2011.

(2) Indiana Department of Environmental Management (IDEM) air quality permits under SIC Code 2999 (Products of Petroleum and Coal, Not Elsewhere Classified).

Table 1. Existing VOC RACT/BACT/LAER Determinations for DDGS Drying

Company	RBLC ID or Permit #	Facility	Date Issued / State	Control Technology	VOC Limit(s)
Fulcrum Centerpoint, LLC	*Pending*	*Fixed Bed Tubular Fischer Tropsch (FT) Synthesis Reactor*	*Pending IN*	*Utility Boiler*	*98.0% overall control* *10 ppmvd* *1.23 lb/hr*
Existing BACT Determinations					
Targa Midstream Services, LLC – Mont Belvieu Fractionator	TX-0912	Amine Unit	2/5/2021 TX	Route flash drum to fuel system and acid gas vent to thermal oxidizer during normal operations. Route both to flare during MSS activities.	99.00% overall efficiency Follow good operating and maintenance practices
		TEG Dehydrator			99.90% overall efficiency Follow good operating and maintenance practices
		Caustic Treatment and Oil Separation		Route the disulfide oil stream to thermal oxidizer during normal operations and to flare during MSS activities.	99.00% overall efficiency Follow good operating and maintenance practices.
Requirements for this source are LAER and therefore not applicable in determining BACT for the proposed source.					
The Premcor Refining Group, INC. – Port Arthur Refinery	TX-0906	SRU	10/30/2020 TX	N/A	Good combustion practices
Riverview Energy Corporation	IN-0317	Sulfur Recovery System TGTUB	6/11/2019 IN	N/A	0.0054 lb/MMBtu 0.2800 lb/hr
		Sulfur Block Flare		N/A	0.0054 lb/MMBtu in sweep and pilot mode 98.00% DRE when flaring a process stream
Rio Grande LNG LLC – Rio Bravo Pipeline Facility	TX-0851	LNG Export Acid Gas Removal Unit	12/17/2018 TX	TO	99.90% overall efficiency (PSD BACT)

Company	RBLC ID or Permit #	Facility	Date Issued / State	Control Technology	VOC Limit(s)
Premcor Refining Group – Valero Port Arthur Refinery	TX-0847	TGI	9/16/2018 TX	N/A	0.0800 lb/MMBtu Good combustion practices
Port Arthur LNG, LLC – Port Arthur LNG Export Terminal	TX-0790	LNG Export Acid Gas Recovery, Tanks & Loading	2/17/2019 TX	TO	99.90% overall efficiency (PSD BACT)
BP Products, North America, Inc. – BP-Husky Refining, LLC	OH-0357	Sulfur Recovery Unit (3), Claus sulfur recovery plant	9/20/2013 OH	N/A	6.20 ton/yr each SRU
		Amine Treating Unit		N/A	5.00 ton/yr from equipment leaks
Indiana Gasification, LLC	IN-0166	Acid Gas Removal Unit Vents	6/27/2012 IN	RTO	98.00% overall efficiency 1.05 lb/hr 3-hour average
Brightmark Plastics Renewal Indiana 2 LLC (formerly RES Polyflow, LLC)	IN-0251	Plastics to Fuel Conversion	8/3/2016 IN	Process fuel gas combustion to generate heat required for processing	98.00% overall efficiency 606.00 lb/MMCF 3 hours

Fulcrum proposes to route the FT reactor purge gas to the utility boiler to supplement natural gas requirements with an overall VOC control efficiency of 98.0% as BACT. Thermal oxidizers, unlike boilers, can achieve a 99.9% control efficiency by using supplemental natural gas to increase the temperature, thereby increasing the destruction efficiency. The amount of purge gas that is used by the boiler offsets the amount of required natural gas combustion by the boiler by approximately 12.8%. By offsetting the amount of natural gas combustion, operating the FT reactor with use of a boiler is more cost effective than a thermal oxidizer to reduce VOC emissions. Furthermore, based on the review of the RBLC and existing permits, thermal oxidizers are mainly used at petroleum refineries (SIC code 2911) and not at facilities that convert plastic or other feedstocks to fuel (SIC code 2999), such as Brightmark Plastics Renewal Indiana 2 LLC.

IDEM is aware that that the above control technologies may be able to periodically achieve control efficiencies that exceed 98% under certain operating conditions. However, BACT must be achievable on a consistent basis under normal operational conditions. BACT limitations do not necessarily reflect the highest possible control efficiency achievable by the technology on which the emission limitation is based. The permitting authority has the discretion to base the emission limitation on a control efficiency that is somewhat lower than the optimal level. There are several reasons why the permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. In that case, setting the emission limitation to reflect the highest control efficiency would make violations of the permit unavoidable. To account for this possibility, a permitting authority must be allowed a certain degree of discretion to set the emission limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the Permittee to achieve compliance consistently. While we recognize that greater than 98% may be achievable as an average during testing, IDEM allows for sources to include a safety factor, or margin of error, to allow for minor variations in the operation of the emission units and the control device.

Step 5 – Select BACT

The following is the VOC BACT for the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor. Pursuant to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements) and FESOP No. F089-44042-00660, the one (1) fixed bed tubular Fischer Tropsch (FT) Synthesis reactor, identified as FT Reactor, shall use Best Available Control Technology (BACT), which has been determined to be the following:

(a) The VOC emissions from the fixed bed tubular Fischer Tropsch (FT) Synthesis reactor shall be controlled by the utility boiler (BOIL) except when flaring the VOC emissions during startup and shutdown.

(b) The utility boiler (BOIL) shall operate with an overall VOC control efficiency (including the capture efficiency and destruction efficiency) of not less than 98.0% or the VOC outlet concentration shall not exceed 10 ppmvd of VOC at 100% capture.

(c) VOC emissions from the utility boiler stack (SV10) shall not exceed 1.23 lb/hr.

IDEM Contact

(a) Questions regarding this BACT Analysis can be directed to Andrew Belt at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 232-3217 or toll free at 1-800-451-6027 extension 2-3217.

(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 Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2356.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

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

Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Flyn van Ewijk
Fulcrum Centerpoint, LLC
4900 Hopyard Road
Pleasanton, CA 94588

DATE: August 16, 2022

FROM: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
FESOP – New Source Construction (Minor PSD/EO)
089-44042-00660

This notice is to inform you that a final decision has been issued for the air permit application referenced above.

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. In addition, the Notice of Decision has been sent to the OAQ Permits Branch Interested Parties List and, if applicable, the Consultant/Agent and/or Responsible Official/Authorized Individual.

The final decision and supporting materials are available electronically; the original signature page is enclosed for your convenience. The final decision and supporting materials available electronically at:

IDEM's online searchable database: http://www.in.gov/apps/idem/caats/ . Choose Search Option **by Permit Number**, then enter permit 44042

and

IDEM's Virtual File Cabinet (VFC): https://www.in.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

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, or have difficulty accessing the documents online, 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 8/20/20-acces via website

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Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

August 16, 2022

TO: Gary Public Library and Cultural Center

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Fulcrum Centerpoint, LLC
Permit Number: 089-44042-00660

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 1/9/2017

Mail Code 61-53

IDEM Staff	KBOURQUE 8/16/2022 Page 1 of 4 Fulcrum Centerpoint LLC 089-44042-00660 (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		Flyn van Ewijk Fulcrum Centerpoint LLC 4900 Hopyard Rd Pleasanton CA 94588 (Source CAATS) Sent Via UPS Campus Ship									
2		Rick Barazza Vice President Fulcrum Centerpoint LLC 4900 Hopyard Rd Pleasanton CA 94588 *(RO CAATS)*									
3		Gary City Health Department 1145 W 5th Ave Gary IN 46402 *(Health Department)*									
4		Craig Hogarth 7901 W Morris St Indianapolis IN 46231 *(Affected Party)*									
5		Lake County Commissioners 2293 N Main St, Bldg A, 3rd Floor Crown Point IN 46307 *(Local Official)*									
6		Portage City Council and Mayors Office 6070 Central Ave Portage IN 46368 *(Local Official)*									
7		Anthony Copeland 2006 E 140th St East Chicago IN 46312 *(Affected Party)*									
8		Barbara G Perez 506 Lilac St East Chicago IN 46312 *(Affected Party)*									
9		Mr. Robert Garcia 3733 Parrish Ave East Chicago IN 46312 *(Affected Party)*									
10		Ms. Karen Kroczek 8212 Madison Ave Munster IN 46321-1627 *(Affected Party)*									
11		Joseph Hero 11723 S Oakridge Dr St. John IN 46373 *(Affected Party)*									
12		Walt Breitinger 255 Park Ave Valparaiso IN 46383 *(Affected Party)*									
13		Kay Nelson Northwest Indiana Forum 6100 Southport Rd Portage IN 46368 (Affected Party)									
14		Gary City Council 401 Broadway #209 Gary IN 46402 *(Local Official)*									
15		City of Gary Dept. of Environmental Affairs 401 Broadway, Ste 304 Gary IN 46402 *(Local Official)*									

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2		Gary Public Library and Cultural Center 220 W 5th Ave Gary IN 46402-1270 *(Library)*									
3		George Smolka 337 S Griffith Blvd Griffith IN 46319 *(Affected Party)*									
4		Jeff Mayes News-Dispatch 422 Franklin St Michigan City IN 46360 *(Affected Party)*									
5		Lake County Health Department 2900 W 93rd Ave Crown Point IN 46307 *(Health Department)*									
6		Thomas Yonge Yonge Development Services LLC 3168-E US Hwy 17 Fleming Island FL 32003 *(Consultant)*									
7		Baltimore & Ohio Railroad 500 Water St Jacksonville FL 32202 *(Affected Party)*									
8		Majestic Star Casino LLC One Buffington Harbor Dr Gary IN 46406 *(Affected Party)*									
9		Northern Indiana Public Service 290 W Nationwide Blvd Columbus OH 43215 *(Affected Party)*									
10		City of Gary Redevelopment Commission 839 Broadway Gary IN 46402 *(Affected Party)*									
11		Consolidated Rail Corporation 3 Commercial Pl, Taxation Dept BO Norfolk VA 23510 *(Affected Party)*									
12		Carmeuse Lime Inc 6920 Pointe Inverness Way Fort Wayne IN 46804 *(Affected Party)*									
13		Dorreen Carey 7304 Indian Boundary Gary IN 46403 (Affected Party)									
14		Jennifer Rudderham 7905 Hemlock Ave Gary IN 46403 *(Affected Party)*									
15		Carolyn McCrady 8241 Locust Ave Gary IN 46403 *(Affected Party)*									

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1		Kimmie Gordon Founder/Director Brown Faces Green Spaces 5607 E 3rd Pl Gary IN 46403 (Affected Party)									
2		Lin Kaatz Chary 7726 Locust Ave Gary IN 46403 *(Affected Party)*									
3		Mary Cossey 1911 Polk St Gary IN 46407 *(Affected Party)*									
4		Adriane Blaesing 9117 Marigold Ln Munster IN 46321 *(Affected Party)*									
5		Michael Santos 7760 New Hampshire Ave Hammond IN 46323 *(Affected Party)*									
6		Bridgette Murray 7305 Oak Ave Gary IN 46403 *(Affected Party)*									
7		LaTasha Hall 544 Dallas St Gary IN 46406 *(Affected Party)*									
8		Dr. Julie Peller 1320 Brassie Ave Chesterton IN 46304 *(Affected Party)*									
9		Ragen Hatcher 907 N Montgomery St Gary IN 46403 *(Affected Party)*									
10		Eddie Melton 1123 N Wayne St Gary IN 46403 *(Legislator)*									
11		Becky Hanscom 7310 Indian Boundary Gary IN 46403 *(Affected Party)*									
12		Wynton Jones 1229 W 52nd Dr. Apt H188 Merrillville IN 46410 *(Affected Party)*									
13		Penelope Love 4449 E 13th Ave Gary IN 46403 (Affected Party)									
14		Larry Lapidus 721 N Gibson St Gary IN 46403 *(Affected Party)*									
15		Beverly Lewis 452 Lincoln St Gary IN 46402 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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Mail Code 61-53

IDEM Staff	KBOURQUE 8/16/2022 Page 4 of 4 Fulcrum Centerpoint LLC 089-44042-00660 (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		Mary Ann Sumner 639 Morgan St Gary IN 46403 (Affected Party)									
2		Joe Jamnk Fire Department 200 E 5th Ave Gary IN 46402 *(Affected Party)*									
3		Paula Tillman 713 E Rogers, 1017 Beverly Shores IN 46301 *(Affected Party)*									
4		Bryan Cossey 1911 Polk St Gary IN 46407 *(Affected Party)*									
5		Karen Williams 8044 Lakewood Ave Gary IN 46403 *(Affected Party)*									
6		Bianca Hall 544 Dallas St Gary IN 46406 *(Affected Party)*									
7		Ms. Gloria Moreno 2378 Jennings St Gary IN 46404 *(Affected Party)*									
8											
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13											
14											
15											

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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