INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

100 N. Senate Avenue • Indianapolis, IN 46204

(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

TO: Interested Parties / Applicant

DATE: October 11, 2013

RE: IPL - Eagle Valley/109-32471-00004

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

Notice of Decision: Approval - Effective Immediately

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

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:
(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:
(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

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

Enclosures
FNPER.dot 6/13/13

IDEM

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Ms. Angelique Oliger
IPL - Eagle Valley
1 Monument Circle
Indianapolis, IN 46204

October 11, 2013

Re: 109-32471-00004
PSD/Significant Source Modification to
Part 70 Renewal No.: T 109-26292-00004

Dear Ms. Oliger:

IPL Eagle Valley Generating Station was issued a Part 70 Operating Permit Renewal on December 2, 2008 for an electric utility generating station. A letter requesting changes to this permit was received on October 31, 2012. Pursuant to 326 IAC 2-7-10.5 the following emission units are approved for construction at the source:

(a) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

(b) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

(c) One (1) natural gas fired Dew Point Heater, identified as emission unit EU-4, permitted in 2013, with a rated heat input capacity of 20.8 MMBtu/hr exhausting to stack S-4.

Insignificant and Trivial Activities

The source also consists of the following insignificant activities as defined in 326 IAC 2-7-1(21):

(a) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(b) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

(c) One (1) evaporative cooling tower, identified as emission unit U-7, with a rated circulation rate of 192,000 gpm to provide non-contact cooling water to the steam turbine condenser, permitted in 2013, and equipped with high efficiency drift eliminators.

(d) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit F-1, permitted in 2013, with fugitive emissions controlled by full enclosure.

(e) Fugitive equipment leaks from the natural gas supply lines, identified as F-2 controlled by a Leak Detection and Repair (LDAR) program.

(f) Three (3) Turbine Lube Demister Vents, permitted in 2013.

The following construction conditions are applicable to the proposed project:

General Construction Conditions

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

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

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

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

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

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

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

All other conditions of the permit shall remain unchanged and in effect. For your convenience, the entire Part 70 Operating Permit as modified will be provided at issuance.

This decision is subject to the Indiana Administrative Orders and Procedures Act – IC 4-21.5-3-5. If you have any questions on this matter, please contact Josiah Balogun, OAQ, 100 North Senate Avenue, MC 61-53, Room 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Josiah Balogun or extension (4-5257), or dial (317) 234-5257.

Sincerely,

Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Attachments:
Updated Permit
Technical Support Document
PTE Calculations

JB

cc: File – Morgan County
Morgan County Health Department
U.S. EPA, Region V
Compliance and Enforcement Branch

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PREVENTION OF SIGNIFICANT DETERIORATION SIGNIFICANT SOURCE MODIFICATION TO A PART 70 OPERATING PERMIT OFFICE OF AIR QUALITY

Indianapolis Power and Light Company (IPL) Eagle Valley Generating Station (formerly H. T. Pritchard Generating Station) 4040 Blue Bluff Road, Martinsville, Indiana 46151

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

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

PSD/Significant Source Modification No.: 109-32471-00004	
Issued by: Matt Stuckey, Branch Chief Permits Branch Office of Air Quality	Issuance Date: October 11, 2013

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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.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)] [326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

Source Address:	4040 Blue Bluff Road, Martinsville, Indiana, 46151
Mailing Address:	4040 Blue Bluff Road, Martinsville, Indiana, 46151
Source Telephone:	765-349-3413
SIC Code:	4911
County Location:	Morgan
County Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules; Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

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

(a) Two (2) no. 2 fuel oil fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) for control of NO_X emissions, which was voluntarily installed and is not required to operate. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(f) One (1) distillate oil fired generator, identified as Unit PR-10, constructed in 1967, with a design heat input capacity of 28.4 million Btu per hour (MMBtu/hr), exhausting to stack PR10-1.

(g) Coal transfer facilities, with a maximum throughput of 800 tons per hour, with a dust suppression system.

(h) Rail car unloading, coal pile unloading, and coal storage, with a maximum capacity of 800 tons per hour.

(i) Coal crushers, identified as 1A and 1B, with a maximum combined capacity of 800 tons per hour, each using an enclosure for dust control.

(j) One (1) pneumatic fly ash storage silo and handling system, to be constructed in 2009, with a maximum storage capacity of 300 tons and a maximum throughput capacity of 10.0 tons of fly ash per hour. The particulate emissions from the silo loadout to trucks are uncontrolled and exhaust to the atmosphere. The particulate emissions from the silo storage will be controlled by a baghouse, identified as Silo Baghouse, and exhausting to a stack, identified as Silo Stack. The particulate emissions from fly ash conveyance are controlled by a dust collector, identified as Fly Ash Collector, and exhausting to a stack, identified as Vacuum Blower Stack.

Note: The pneumatic fly ash storage silo and handling system was never constructed.

The New Combined Cycle Combustion Turbine Generation Facility Emission Units:

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

(l) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

(m) One (1) natural gas fired Dew Point Heater, identified as emission unit EU-4, permitted in 2013, with a rated heat input capacity of 20.8 MMBtu/hr exhausting to stack S-4.

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

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

(a) Coal bunker and coal scale exhausts. [326 IAC 6-3] [326 IAC 5]

Before the startup of the Combined Cycle Combustion Turbine Generation Facility, the Coal bunker and coal scale exhausts shall be permanently shut down and decommissioned.

(b) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM_{10} 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(1) Wet process ash handling, with hydroveyors conveying ash to storage ponds. [326 IAC 6-4]

Before the startup of the Combined Cycle Combustion Turbine Generation Facility, the Wet process ash handling shall be permanently shut down and decommissioned.

(2) Ponded ash handling/removal operations. [326 IAC 6-4]

(3) Truck traffic on paved road. [326 IAC 6-4]

The New Combined Cycle Combustion Turbine Generation Facility Insignificant Emission Units:

(c) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(d) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

(e) One (1) evaporative cooling tower, identified as emission unit U-7, rated with a circulation rate of 192,000 gpm to provide non-contact cooling water to the steam turbine condenser, permitted in 2013, and equipped with high efficiency drift eliminators.

(f) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit F-1, permitted in 2013, with fugitive emissions controlled by full enclosure.

(g) Fugitive equipment leaks from the natural gas supply lines, identified as F-2 controlled by a Leak Detection and Repair (LDAR) program.

(h) Three (3) Turbine Lube Demister Vents, permitted in 2013.

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

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

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

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

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3).

SECTION B GENERAL CONDITIONS

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

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

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

(a) This permit, T 109-26292-00004, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

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

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

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

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

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

B.4 Enforceability [326 IAC 2-7-7]

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

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

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

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

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

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

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ, may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The submittal by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34). Upon request, the Permittee shall also furnish to IDEM, OAQ, copies of records required to be kept by this permit.

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

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

(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form, with each submittal requiring certification. One (1) certification can cover multiple forms in one (1) submittal.

(c) A responsible official is defined at 326 IAC 2-7-1(34).

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

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

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

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent; and

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

(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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) for the source as described in 326 IAC 1-6-3. At a minimum, the PMP shall include:

(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.

(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 or potential to emit. The PMP do not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

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

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

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

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

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

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

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

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(9) be revised in response to an emergency.

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

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

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report.

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

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

for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

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

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

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

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

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

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

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

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

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

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

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

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

(a) All terms and conditions of permits established prior to T 109-26292-00004 and issued pursuant to permitting programs approved into the state implementation plan have been either

(1) incorporated as originally stated,

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

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

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

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

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

B.15 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]

(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provisions), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported 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

using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. 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.

The Quarterly Deviation and Compliance Monitoring Report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

B.16 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)] [326 IAC 2-7-8(a)] [326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

(1) That this permit contains a material mistake.

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

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

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

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

B.17 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] [326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ, and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

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

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

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

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

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

B.18 Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12] [40 CFR 72]

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

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

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

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

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.19 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12 (b)(2)]

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

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

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

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

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

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

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

(4) The Permittee notifies the:

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

and

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

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

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

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

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

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

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

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

B.21 Source Modification Requirement [326 IAC 2-7-10.5]

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

(b) Any modification at an existing major source is governed by the requirements of 326 IAC 2-2.

B.22 Inspection and Entry [326 IAC 2-7-6] [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 Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

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

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

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

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

B.23 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

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

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

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

The application which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.24 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

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

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

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

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

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

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping 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 or incinerate any waste or refuse except as provided in 326 IAC 4-2 and 326 IAC 9-1-2.

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

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

C.6 Motor Vehicle Fugitive Dust Sources [326 IAC 6-4-4]

Pursuant to 326 IAC 6-4-4, no vehicle shall be driven or moved on any public street, road, alley, highway, or other thoroughfare, unless such vehicle is so constructed as to prevent its contents from dripping, sifting, leaking, or otherwise escaping therefrom so as to create conditions which result in fugitive dust. This section applies only to the cargo any vehicle may be conveying and mud tracked by the vehicle.

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

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

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140.

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

C.9 Performance Testing [326 IAC 3-6]

(a) All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing 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 IDEM, OAQ.

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 certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(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 certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

C.11 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

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

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

days provided the Permittee notifies:

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

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

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

(c) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(d) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

C.12 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. For a boiler, the COM shall be in operation at all times that the induced draft fan is in operation.

(b) All continuous opacity monitoring systems shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

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

(d) Whenever a COM is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more and a backup COM cannot be brought on-line, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the opacity from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not later than twenty-four hours after the start of the malfunction or down time; provided, however, that if such 24-hour period ends during the period beginning two (2) hours before sunset and ending two (2) hours after sunrise, then such visible emissions readings shall begin within four (4) hours of sunrise on the day following the expiration of such 24-hour period.

(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.

(3) Method 9 readings may be discontinued once a COM is online.

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5.

C.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)]

(a) The Permittee shall calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment.

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

(d) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for maintenance or repairs, the following shall be used as an alternative to continuous data collection

(1) If the CEM is required for monitoring NO_X or SO_2 emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 10-4 (NO_X Budget Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D - Missing Data Substitution Procedures.

(2) IF the CEM is not used to monitor NO_X or SO_2 emissions pursuant to 40 CFR 75 or 326 IAC 10-4, then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 326 IAC 10-4, 40 CFR 60 or 40 CFR 75.

C.14 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60 Appendix A, 40 CFR 60 Appendix B, 40 CFR 63, or other approved methods as specified in this permit.

C.15 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

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

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

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

C.16 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.17 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

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

C.18 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) Upon detecting an excursion or exceedance, the Permittee shall 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 emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Corrective actions may include, but are not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned 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 within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(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 maintain the following records:

(1) monitoring data;

(2) monitor performance data, if applicable; and

(3) corrective actions taken.

C.19 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one-hundred and twenty (120) 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 the certification by the “responsible official” as defined by 326 IAC 2-7-1(34)

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

C.20 Emission Statement [326 IAC 2-7-5(3)(C)(iii)] [326 IAC 2-7-5(7)] [326 IAC 2-7-19(c)] [326 IAC 2-6]

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

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

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

The statement must be submitted to:

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

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

(b) The emission statement 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.21 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. 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, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

(c) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A), 40 CFR 51.165(a)(6)(vi)(B), 40 CFR 51.166(r)(6)(vi)(a), and/or 40 CFR 51.166(r)(6)(vi)(b)) that a “project” (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, document and maintain the following records:

(A) A description of the project.

(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(rr)(2)(A)(iii) and/or 326 IAC 2-3-1 (mm)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A) and/or 40 CFR 51.166(r)(6)(vi)(a)) that a “project” (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

C.22 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) The report required in (a) of this condition and reports required by conditions in Section D of 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

(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) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(e) 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.

(f) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any “project” (as defined in 326 IAC 2-2-1 (qq) and/or 326 IAC 2-3-1 (ll)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (xx) and/or 326 IAC 2-3-1 (qq), for that regulated NSR pollutant, and

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(g) The report for project at an existing emissions unit shall be submitted within sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee deems fit to include in this report.

Reports required in this part shall be submitted to:

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

(h) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

Stratospheric Ozone Protection

C.23 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 the standards for recycling and emissions reduction:

(a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

(b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

(c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(a) Two (2) no. 2 fuel oil-fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

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

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

D.1.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.1 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.1.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-2]

(a) Pursuant to 326 IAC 6-2-2(a) (Particulate Emissions Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(b)), the PM emissions from Units 1, 2, 3, 4, 5, and 6 shall not exceed 0.23 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{0.87}{Q^{0.16}}$$

Where Q = total source capacity (MMBtu/hr) on June 8, 1972
= 4,071 MMBtu/hr

(b) Pursuant to 326 IAC 6-2-2(b), the PM emissions from Units 1 and 2 shall not exceed 0.10 pound per million Btu heat input (lb/MMBtu), which is less than 0.23 lb/MMBtu, as requested by the source in a letter dated August 26, 2008.

D.1.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), the following applies to Eagle Valley Units 1 and 2:

(1) When starting a fire in a boiler, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period. [326 IAC 5-1-3(a)]

(2) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the forty percent (40%) opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60) minute period. The averaging periods in excess of the limit set in 326 IAC 5-1-2 shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

(b) If this facility cannot meet the opacity limitations in (a)(1) and (a)(2) of this condition, the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

D.1.3 Sulfur Dioxide (SO_2) [326 IAC 7-4-11]

Pursuant to 326 IAC 7-4-11 (Morgan County Sulfur Dioxide Emission Limitations), the SO_2 emissions from Unit 1 and Unit 2 shall not exceed 0.37 pounds per million Btu (lbs/MMBtu) each. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated using a calendar month average.

Compliance Determination Requirements

D.1.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11] [326 IAC 3-6]

Compliance with the particulate limitations in Condition D.1.1(b) and with the Opacity limits in Section C - Opacity and Temporary Alternative Opacity Limitations for startup shall be determined as follows:

(a) Compliance with the particulate limitations shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. PM testing with both units operating and exhausting to the common stack is permitted. [326 IAC 3-6]

(b) Opacity testing shall be performed in conjunction with the particulate emissions testing in accordance with 40 CFR 60, Appendix A, Method 9. The Method 9 opacity testing (VE readings) shall be recorded for the full duration of the sampling time for each sampling repetition that occurs during daylight hours. [326 IAC 3-5-1(c)(2)(A)(ii)]
[326 IAC 5-1-4(a)(1)]

(c) To demonstrate compliance with the Temporary Alternative Opacity Limitation for boiler startups, opacity testing shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, during daylight hours of the startup from light-off to completion of start-up.
[326 IAC 3-5-1(c)(2)(A)(ii)] [326 IAC 5-1-4(a)(1)]

(d) The PM stack testing and Method 9 opacity testing shall be repeated as follows:

(1) By December 31 of every second calendar year following this valid compliance demonstration; or

(2) If a unit is not operated at least 1,000 hours in the 2 years since the previous stack test, then testing shall be repeated at least once every 1,000 hours of operation for that unit, or five (5) calendar years from the date of the last valid compliance demonstration, whichever occurs first.

For the purpose of this permit, “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

(e) Testing shall be conducted in accordance with Section C - Performance Testing.

D.1.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 7-2] [326 IAC 7-4-11]

Compliance shall be determined utilizing one of the following options:

(a) Pursuant to 326 IAC 3-7-4, 326 IAC 7-2, and 326 IAC 7-4-11, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed the equivalent of 0.37 pounds per MMBtu each, using a calendar month average, by:

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

(2) Providing analysis of fuel oil samples collected and analyzed in accordance with 326 IAC 3-7-4(a).

(A) Oil samples shall be collected from the tanker truck load during or prior to transferring fuel to the storage tank; or

(B) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank.

(b) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

D.1.6 RESERVED

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

D.1.7 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the fuel oil-fired boiler exhaust shall be performed once per day during normal daylight operations when one or both of Units 1 and 2 are in operation and burning fuel oil. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(e) If abnormal emissions are observed at any boiler exhaust, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

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

D.1.8 Record Keeping Requirements [326 IAC 2-7-5(3)]

(a) To document compliance with the applicable opacity limits and Conditions D.1.1 and D.1.2, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the opacity and particulate limits established in Section C - Opacity and Conditions D.1.1 and D.1.2.

(1) Data and results from the most recent stack test and accompanying Method 9 visible emissions evaluation results for Units 1 and 2.

(2) Results of the visible emission notations of the stack 1-1 exhaust.

(b) To document compliance with Conditions D.1.3 and D.1.5, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained shall be complete and sufficient to establish compliance with the SO_2 limit as required in Conditions D.1.3 and D.1.5.

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

(2) Monthly weighted average sulfur content.

(3) Fuel heat content.

(4) Fuel consumption.

(5) Monthly weighted average sulfur dioxide emission rate in pounds per million Btus (lb/MMBtu).

(c) To document compliance with Condition D.1.7, the Permittee shall maintain daily records of the visible emission notations of the Boiler stack exhaust. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.1.9 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 7-2(c)]

A quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Condition D.1.3 shall be submitted to the address listed in Section C - General Reporting Requirements of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.2 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB to control NO_X emissions. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) to control NO_X emissions. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

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

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

D.2.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.2 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-2]

(a) Pursuant to 326 IAC 6-2-2 (Particulate Emissions for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(b)), the PM emissions from Units 1, 2, 3, 4, 5, and 6 shall not exceed 0.23 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{0.87}{Q^{0.16}}$$

Where Q = total source capacity (MMBtu/hr) on June 8, 1972
= 4,071 MMBtu/hr

(b) Pursuant to 326 IAC 6-2-2(b), the PM emissions from Units 3, 4, 5 and 6 shall not exceed 0.27 pound per million Btu heat input (lb/MMBtu), as requested by Indianapolis Power and Light Company in a letter dated April 12, 1988.

D.2.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), the following applies:

(1) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed two and one-half (2.5) hours (twenty-five (25) six (6)-minute averaging periods) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit, whichever occurs first. [326 IAC 5-1-3(e)]

(2) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed one (1) hour (ten (10) six (6)-minute averaging periods). [326 IAC 5-1-3(e)]

(3) Operation of the electrostatic precipitator is not required during these times.

(4) During the above startup and shutdown periods all reasonable efforts shall be made to minimize the number and magnitude of the exceedances.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60) minute period. The averaging periods in excess of the limit set in 326 IAC 5-1-2 shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

D.2.3 Sulfur Dioxide (SO_2) [326 IAC 7-4-11]

Pursuant to 326 IAC 7-4-11 (Sulfur Dioxide Emission Limitations for Morgan County):

(a) SO_2 emissions from Unit 3 shall not exceed 0.37 pounds per million Btu (lbs/MMBtu), compliance with which shall be determined as specified in 326 IAC 7-2-1(c), using a thirty (30) day rolling weighted average. [326 IAC 7-4-11(2)]

(b) SO_2 emissions from Units 4, 5, and 6 shall not exceed 3.04 pounds per million Btu (lbs/MMBtu) each, compliance with which shall be determined as specified in 326 IAC 7-2-1(c), using a thirty (30) day rolling weighted average. [326 IAC 7-4-11(2)]

(c) As an exception to the emission limitations specified in (a) and (b), pursuant to 326 IAC 7-4-11(7), at any time in which IPL burns coal on Unit 3, the thirty (30) day rolling weighted average for sulfur dioxide emissions from Units 3, 4, 5, and 6 shall be limited to two and fifty-seven hundredths (2.57) pounds per million Btu each. [326 IAC 7-4-11(3)]

Compliance Determination Requirements

D.2.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to determine compliance with the PM limitation in Condition D.2.1(b) for each units (Units 3, 4, 5 and 6), the Permittee shall conduct before December 31, a performance stack test utilizing methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following this valid compliance demonstration. For the purpose of this permit, "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive. Testing shall be conducted in accordance with Section C - Performance Testing.

D.2.5 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitators (ESPs) shall be operated at all times that the boilers vented to the ESPs are in operation. Each flue gas conditioning (FGC) system on Unit 3, Unit 4 and Unit 5 shall be used with the corresponding ESP as necessary to maintain compliance with this permit.

D.2.6 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems for Units 3, 4, 5 and 6 shall be calibrated, maintained, and operated for measuring opacity, SO_2, and either CO_2 or O_2, which meet the performance specifications of 326 IAC 3-5-2.

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

(c) Pursuant to 326 IAC 3-5-4, if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 326 IAC 10-4, or 40 CFR 75.

(e) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

D.2.7 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 7-2] [326 IAC 7-4-11]

(a) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data obtained in accordance with procedures specified under 326 IAC 3-7 may be used to demonstrate compliance as follows:

(1) Pursuant to 326 IAC 7-4-11(6), on a day for which Unit 3 does not burn any coal, compliance with the sulfur dioxide emission limitations in 326 IAC 7-4-11(2) shall be determined as specified in 326 IAC 7-2-1(c), using a thirty (30) day rolling weighted average.

(2) Pursuant to 326 IAC 7-4-11(7), on a day for which Unit 3 burns any coal, if the thirty (30) day rolling weighted average for any unit is above two and fifty-seven hundredths (2.57) pounds per million Btu, then 326 IAC 7-2-1(c)(1) does not apply, and the daily average emission rate for that unit for that day shall not exceed two and fifty-seven hundredths (2.57) pounds per million Btu.

In the alternative, SO_2 emissions may be determined by use of CEM in lieu of any other method prescribed herein.

(b) Pursuant to 326 IAC 7-4-11(8), for the purposes of determining compliance under 326 IAC 7-2-1(b), stack tests performed on Units 3, 4, 5, and 6 shall demonstrate compliance with the most stringent set of limits in effect at any time during the day prior to or during the test based on the Unit 3 operating status and fuel type as indicated by the log maintained pursuant to 326 IAC 7-4-11(9).

D.2.8 RESERVED

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

D.2.9 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) The ability of the ESP to control particulate emissions shall be monitored once per day, when the unit is in operation, by measuring and recording the number of T-R sets in service and the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets.

(b) Reasonable response steps shall be taken in accordance with Section C – Response to Exceedances or Excursions whenever the percentage of T-R sets in service falls below 90 percent (90%). T-R set failure resulting in less than 90 percent (90%) availability is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Exceedances or Excursions shall be considered a deviation from this permit.

D.2.10 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) In the event of emissions exceeding thirty percent (30)%) average opacity for three (3) consecutive six (6) minute averaging periods, appropriate response steps shall be taken in accordance with Section C - Response to Exceedances or Excursions such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below thirty percent (30%). Examples of expected response steps include, but are not limited to, boiler loads being reduced, adjustment of flue gas conditioning rate, and ESP T-R sets being returned to service.

(b) Opacity readings in excess of thirty percent (30%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Exceedances or Excursions, shall be considered a deviation from this permit.

D.2.11 SO_2 Monitor Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

(a) Whenever the SO_2 continuous emission monitoring (CEM) system is malfunctioning or down for repairs or adjustments and a backup CEM is not brought on-line, the following shall be used to provide information related to SO_2 emissions:

(1) If the CEM system is down for less than twenty-four (24) hours and a backup CEM is not brought on-line, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(2) If the CEM system is down for twenty-four (24) hours or more and a backup CEM is not brought on-line, the Permittee shall either:

(A) Conduct fuel sampling as specified in 326 IAC 3-7-2(b). Fuel sample preparation and analysis shall be conducted as specified in 326 IAC 3-7-2(c), 326 IAC 3-7-2(d), and 326 IAC 3-7-2(e). Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring: or

(B) Comply with the relevant requirements of 40 CFR Part 75. Subpart D - Missing Data Substitution Procedures

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

D.2.12 Record Keeping Requirements

(a) To document compliance with the applicable opacity and particulate limits and Conditions D.2.1 and D.2.2, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the opacity and particulate limits in Section C - Opacity and in Conditions D.2.1 and D.2.2.

(1) Data and results from the most recent stack test.

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5.

(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime.

(4) All ESP parametric monitoring readings.

(b) To document compliance with SO_2 Condition D.2.3, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the SO_2 limits as required in Condition D.2.3. The Permittee shall maintain records in accordance with (2) and (3) or (4) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6 and 326 IAC 7-2-1(g).

(2) All fuel sampling and analysis data collected for SO_2 CEM downtime, in accordance with Condition D.2.11.

(3) Calculated actual fuel usage during each SO_2 CEM downtime for the Unit(s) affected by CEM downtime lasting 24 or more hours.

(4) The substitute data used for the missing data periods if data substitution pursuant to 40 CFR Part 75 Subpart D is used to provide data for the SO_2 CEM downtime, in accordance with Condition D.2.11.

(c) Pursuant to 326 IAC 7-4-11(9), the Permittee shall maintain and make available to the department upon request a log of the operating status and fuel type used for Unit 3. In addition, in the quarterly report required by 326 IAC 7-2-1(a), the Permittee shall submit to the department a daily summary indicating fuel type for Unit 3, and, for days on which Unit 3 burned any coal and any thirty (30) day rolling weighted average was greater than two and fifty-seven hundredths (2.57) pounds per million Btu, the Permittee shall submit to the department the daily average sulfur content, heat content, and sulfur dioxide emission rate for Units 3, 4, 5, and 6. For the purposes of this Condition, "department" refers to the Indiana Department of Environmental Management (IDEM).

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.2.13 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 3-5-7] [326 IAC 7-2(c)]

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Condition D.2.3 shall be submitted to the address listed in Section C - General Reporting Requirements of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

(1) Date of downtime.

(2) Time of commencement.

(3) Duration of each downtime.

(4) Reasons for each downtime.

(5) Nature of system repairs and adjustments.

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

SECTION D.3 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(f) One (1) distillate oil fired generator, identified as Unit PR-10, constructed in 1967, with a design heat input capacity of 28.4 million Btu per hour (MMBtu/hr), exhausting to stack PR10-1.

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

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

D.3.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.3 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.3.1 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO_2 emissions from Unit PR-10 shall not exceed 0.5 pound per million Btu (lb/MMBtu).

Compliance Determination Requirements

D.3.2 Sulfur Dioxide Emissions and Sulfur Content] [326 IAC 7-1.1-2] [326 IAC 7-2]

Pursuant to 326 IAC 3-7-4, 326 IAC 7-1.1-2, and 326 IAC 7-2, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed the equivalent of 0.5 lb/MMBtu, using a calendar month average, by:

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

(b) Providing analysis of fuel oil samples collected and analyzed in accordance with 326 IAC 3-7-4(a).

(1) Oil samples shall be collected from the tanker truck load during or prior to transferring fuel to the storage tank; or

(2) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank.

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

D.3.3 Record Keeping Requirements

(a) To document compliance with Condition D.3.1 and D.3.2, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained shall be complete and sufficient to establish compliance with the SO_2 limit as required in Condition D.3.1 and D.3.2.

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

(2) Monthly weighted average sulfur content.

(3) Fuel heat content.

(4) Fuel consumption.

(5) Monthly weighted average sulfur dioxide emission rate in pounds per million Btus (lb/MMBtu).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.3.4 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 7-2(c)]

A quarterly summary of the information to document compliance with Condition D.3.1 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.4 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(g) Coal transfer facilities, with a maximum throughput of 800 tons per hour, with a dust suppression system.

(h) Rail car unloading, coal pile unloading, and coal storage, with a maximum capacity of 800 tons per hour.

(i) Coal crushers, identified as 1A and 1B, with a maximum combined capacity of 800 tons per hour, each using an enclosure for dust control.

Insignificant Activities:
Coal bunker and coal scale exhausts.

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

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

D.4.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.4 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.4.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the coal processing drop points and the particulate emission rate from the coal crushers shall not exceed amounts determined by the following:

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

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

(b) Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0\, P^{0.11} - 40$ where E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour.

When the process weight rate exceeds two hundred (200) tons per hour, the allowable emission may exceed the pounds per hour limitation calculated using the above equation, provided the concentration of particulate in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

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

D.4.2 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of any coal transfer exhaust points shall be performed once per week during normal daylight operations when transferring coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the rail car unloading shall be performed once per week during normal daylight operations when unloading coal. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the coal crusher stack exhaust shall be performed once per week during normal daylight operations when the crusher is in operation. A trained employee shall record whether emissions are normal or abnormal.

(d) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(e) 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.

(f) 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.

(g) If abnormal emissions are observed at a transfer point exhaust or crusher exhaust or from the coal unloading, 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.

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

D.4.3 Record Keeping Requirements

(a) To document compliance with Condition D.4.2, the Permittee shall maintain weekly records of the visible emission notations of the rail car unloading, crusher and coal transfer exhaust. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]:

(j) One (1) pneumatic Fly Ash Conveyance and Silo Storage (fly ash storage silo and handling system), to be constructed in 2009, with a maximum storage capacity of 300 tons and a maximum throughput capacity of 10.0 tons of fly ash per hour. The particulate emissions from the silo loadout to trucks are uncontrolled and exhaust to the atmosphere. The particulate emissions from the silo storage will be controlled by a baghouse, identified as Silo Baghouse, and exhausting to a stack, identified as Silo Stack. The particulate emissions from fly ash conveyance are controlled by a dust collector, identified as Fly Ash Collector, and exhausting to a stack, identified as Vacuum Blower Stack.

Note: The pneumatic fly ash storage silo and handling system was never constructed.

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

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

D.5.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.5 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.5.1 PSD Minor Limits and Nonattainment NSR [326 IAC 2-2] [326 IAC 2-1.1-5]

The Permittee shall comply with the following:

(a) The combined PM emissions from the Fly Ash Conveyance and Silo Storage shall not exceed 3.9 pounds per hour.

(b) The combined PM_{10} emissions from the Fly Ash Conveyance and Silo Storage shall not exceed 2.9 pounds per hour.

Compliance with these limits in combination with other emission units will limit the PM and PM10 emissions from the Fly Ash Conveyance and Silo Storage (fly ash storage and handling system) to less than 25 and 15 tons per year, respectively and render the requirements of 326 IAC 2-2 (PSD) and 326 IAC 2-1.1-5 (Nonattainment NSR) not applicable to the Fly Ash Conveyance and Silo Storage (fly ash storage and handling system) permitted in 2008.

D.5.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the Fly Ash Conveyance and Silo Storage (fly ash storage and handling system) shall not exceed 19.2 pounds per hour, each, when operating at a process weight rate of 10 tons per hour, each. The pound per hour limitation was calculated with the following equation:

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

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

Compliance Determination Requirements

D.5.3 Particulate Matter (PM)

(a) In order to comply with Conditions D.5.1 and D.5.2, the baghouse and fly ash collector shall be in operation at all times when the fly ash storage and handling is in operation.

(b) 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.5.4 Testing Requirements [326 IAC 2-7-6(1)][326 IAC 2-1.1-11]

Within 180 days after initial startup of the fly ash handling and storage system, in order to demonstrate compliance with Conditions D.5.1 and D.5.2, the Permittee shall perform PM/PM10 testing on baghouse and the dust collector controlling the fly ash storage and handling system utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with Section C - Performance Testing.

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

D.5.5 Visible Emissions Notations

(a) Visible emission notations of the fly ash storage and handling stack exhausts shall be performed once per week 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.5.6 Parametric Monitoring

The Permittee shall record the pressure drop across the fly ash storage and handling baghouse and dust collector used in conjunction with the fly ash storage and handling at least once per day when the fly ash storage and handling is in operation. When for any one reading, the pressure drop across the baghouse or the fly ash collector is outside the normal range of 1.0 and 10.0 inches of water, or a range established during the latest stack test 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.

The instrument used for determining the pressure shall comply with condition C.14 - Instrument Specifications, be subject to approval by IDEM, OAQ, and shall be calibrated at least once every six (6) months.

D.5.7 Broken or Failed Bag Detection

(a) For a single compartment baghouse controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has been repaired or replaced.

(b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit has been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in the emissions unit.

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, or dust traces.

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

D.5.8 Record Keeping Requirements

(a) To document compliance with Condition D.5.5 - Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the fly ash storage and handling stack exhaust. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(b) To document compliance with Condition D.5.6 - Parametric Monitoring, the Permittee shall maintain the daily records of the pressure drop across the baghouse and fly ash collector controlling the fly ash storage and handling. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

(c) All records shall be maintained in accordance with Section C - General Record Keeping Requirements of this permit.

SECTION D.6 FACILITY CONDITIONS

Facility Description [326 IAC 2-7-5(15)] Insignificant Activities:

(1) Wet process ash handling, with hydroveyors conveying ash to storage ponds.

(2) Ponded ash handling/removal operations.

(3) Truck traffic on paved road.

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

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

D.6.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the “wet process ash handling with hydroveyors conveying ash to storage ponds” before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.6.1 Fugitive Dust Emission Limitations [326 IAC 6-4-2]

Pursuant to 326 IAC 6-4-2:

(a) Any ash storage pond area generating fugitive dust shall be in deviation from this rule (326 IAC 6-4) if any of the following criteria are violated:

(1) A source or combination of sources which cause to exist fugitive dust concentrations greater than sixty-seven percent (67%) in excess of ambient upwind concentrations as determined by the following formula:

$$P = \frac{100\ (R) - U)}{U}$$

Where
P = Percentage increase
R = Number of particles of fugitive dust measured at downward receptor site
U = Number of particles of fugitive dust measured at upwind or background site

(2) The fugitive dust is comprised of fifty percent (50%) or more respirable dust, then the percent increase of dust concentration in subdivision (1) of this section shall be modified as follows:

$P_R = (1.5 \pm N)\ P$

Where
N = Fraction of fugitive dust that is respirable dust;
P_R = allowable percentage increase in dust concentration above background; and
P = no value greater than sixty-seven percent (67%).

(3) The ground level ambient air concentrations exceed fifty (50) micrograms per cubic meter above background concentrations for a sixty (60) minute period.

(4) If fugitive dust is visible crossing the boundary or property line of a source. This subdivision may be refuted by factual data expressed in subdivisions (1), (2) or (3) of this section. 326 IAC 6-4-2(4) is not federally enforceable.

(b) Pursuant to 326 IAC 6-4-6(6) (Exceptions), fugitive dust from a source caused by adverse meteorological conditions will be considered an exception to this rule (326 IAC 6-4) and therefore not in violation.

Adverse weather conditions do not relieve a source from taking all reasonable measures to mitigate fugitive dust formation and transport. Failure to take reasonable measures during this period may be considered to be a deviation from this permit.

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

D.6.2 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the fly ash storage pond area(s) shall be performed at least once per week 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.

(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 visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, 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.

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

D.6.3 Record Keeping Requirements

(a) To document compliance with Condition D.6.2, the Permittee shall maintain weekly records of the visible emission notations of the fly ash storage pond area(s). The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

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

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

D.7.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 16.8 pounds per hour, each and 0.0066 pounds per MMBtu, each with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 13.9 pounds per hour, each and 0.0055 pounds per MMBtu, each without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(c) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.2 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The H_2SO_4 emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall be limited by restricting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

(b) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.3 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The CO emissions from the CCCTs shall be controlled by a catalytic oxidation; and

(b) The CO emissions shall not exceed 2.0 ppmvd @15% O2 based on a 3-hour average.

(c) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.4 VOC PSD BACT [326 IAC 2-2-3][326 IAC 8-1-6]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)) and 326 IAC 8-1-6, the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The VOC emissions from the CCCTs shall be controlled by a catalytic oxidation;

(b) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hour average.

(c) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hour average.

(d) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.5 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The NOx emissions from the CCCTs shall be controlled by a Selective Catalytic Reduction and Dry Low NOx combustors.

(b) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hour average.

(c) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.6 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The net heat rate shall not exceed 7,750 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(b) The total CO_2e emissions for both combined cycle combustion turbines shall be limited to less than 2,649,570 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

D.7.7 Hazardous Air Pollutants (HAPs) Minor Limits

The emissions of single HAP, formaldehyde, from the combined cycle combustion turbines identified as EU-1 and EU-2, shall be limited to less than nine (9.0) tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with the above limits, combined with the potential to emit formaldehyde emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of formaldehyde and make the source an area source of HAPs.

D.7.8 Startup and Shutdown Limitations for Combustion Turbines [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the following shall apply to each combustion turbine:

(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves consecutive CEMS data points in compliance with the primary BACT limits.

(b) Steady-state operating condition shall be defined as the period of time that the combustion turbine is operating in dry low NOx (premix) mode and in compliance with the primary BACT limit.

(c) A shutdown is defined as operation beginning when the combustion turbine exits dry low-NOx (premix) mode and ending with termination of continuous fuel flow to each turbine.

(d) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(e) Unit Offline is represented by the Unit on-line Time being 0.

(f) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown

For CO and NO_X, the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCTs. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor. Therefore, the source proposes to use the cold start emission totals, per CCCT as a short-term limit during startup/shutdown events, as follows:

CO - 3,390 lb/event

NOx - 429 lb/event

(g) The total NO_X emissions from the combined cycle combustion turbines stacks shall not exceed 68 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(h) The total CO emissions from the combined cycle combustion turbines stacks shall not exceed 565 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(i) The total VOC emissions from the combined cycle combustion turbines stacks shall not exceed 146 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

Compliance Determination Requirements

D.7.9 Oxidation Catalyst

In order to ensure compliance with Conditions D.7.3, D.7.4 and D.7.7, the oxidation catalyst shall be in operation at all times when the natural gas-fired combined cycle combustion turbines are in operation except during periods of startup and shutdown.

D.7.10 Nitrogen Oxide Control

In order to ensure compliance with Condition D.7.5 - NOx PSD BACT, the Selective Catalytic Reduction and Dry Low NOx combustors shall be in operation and control emissions from the natural gas-fired combustion turbines at all times that the natural gas-fired combined cycle combustion turbines are in operation except during periods of startup and shutdown.

D.7.11 H_2SO_4 Compliance Determination Requirements [326 IAC 2-2]

In order to ensure compliance with Condition D.7.2, the Permittee shall maintain a record of the monthly average sulfur content of the natural gas based on vendor data.

D.7.12 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.7.6 - GHGs PSD BACT, the following equation shall be used to determine the CO_2e emissions from the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2:

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

Where:

Fuel Usage (mmscf/month) = monthly fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas or vendor data, if available
CO_2 EF (lb/mmbtu) = 120 lbs/mmbtu for combustion with duct firing and 122 lbs/mmbtu for combustion without duct firing
CH_4 EF (lb/mmbtu) = 0.0022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = 0.00022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

D.7.13 HAPs Minor Limits Calculations

To determine the compliance status with Condition D.7.7 - Hazardous Air Pollutants (HAPs) minor Limits, the following equation shall be used to determine formaldehyde emissions from the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2:

L (tons/month)= (7.1×10^{-4} x Qu + C x Qc)/2000 lbs/ton

Where:

L = 9 tons of (formaldehyde) per 12 month rolling period.

7.1×10^{-4} is the uncontrolled emission factor for formaldehyde (lbs/MMBtu)

Qu = 12- month rolling total heat input to the CT units (MMBtu) when the oxidation catalyst is not fully operational during startup and shutdown conditions

Qc = 12- month rolling total heat input to the CT units (MMBtu) when the oxidation catalyst is fully operational (includes heat input to duct burners).

C = is the controlled emission factor for formaldehyde (lbs/MMBtu), which would be based on stack test results of the CCCTs. Prior to stack testing the factor will be conservatively assumed to equal 60% of the uncontrolled emission factor.

D.7.14 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5][326 IAC-2-2-3]

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

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

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

(d) Whenever a NOx or O_2 CEMS is down for more than twenty-four (24) hours, the Permittee shall monitor the catalyst inlet temperature used in conjunction with the CCCT units with a continuous temperature monitoring system and comply with the following:

The Permittee shall measure the operating temperature of the catalyst inlet bed temperature no less often than once per four (4) hours. In the event of a monitoring system malfunction, failure to measure the operating temperature of the catalyst bed inlet temperature is not a deviation of the permit. Failure to take response steps shall be considered a deviation from the permit. If the measured temperature is below the minimum temperature as supplied by the manufacturer, reasonable response steps shall be taken to return the catalyst bed inlet temperature to the required minimum temperature. A reading that is below the minimum temperature is not a deviation from this permit. Failure to take response steps in accordance with Section C – Response to Excursions or Exceedances shall be considered a deviation from this permit.

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

D.7.15 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Conditions D.7.1 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with and without the duct burners in operation. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.7.3 - CO PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct CO emissions stack testing of the emissions from the oxidation catalyst controlling the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with the duct burners in operation. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.7.4 - VOC PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from oxidation catalyst controlling the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with and without the duct burners in operation. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) In order to demonstrate compliance with Condition D.7.6(a) - GHGs PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct net heat rate performance testing for combined cycle combustion turbines utilizing methods as approved by the commissioner. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) In order to demonstrate compliance with Condition D.7.7 - Hazardous Air Pollutants (HAPs) minor Limits, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct HAPs (formaldehyde) emissions stack testing of the emissions from oxidation catalyst controlling the combined cycle combustion turbines utilizing methods as approved by the commissioner. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

D.7.16 Oxidation Catalyst Parametric Monitoring [40 CFR 64]

(a) In order to ensure compliance with Conditions D.7.3, D.7.4 and D.7.7, a continuous monitoring system shall be calibrated, maintained, and operated on the oxidation catalyst for measuring operating temperature. For the purposes of this condition, continuous monitoring means recording the temperature no less often than every 15 minutes. The output of this system shall be recorded as a three (3) hour average. From the date of the start up of the oxidation catalyst until the approved stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 3-hour average temperature of 500^{o}F.

(b) On and after the date the approved stack test results are available, the Permittee shall operate the oxidation catalyst at or above the three (3) hour average temperature specified by the catalyst manufacturer for VOC, CO and formaldehyde control or as established during the most recent compliant stack test.

(c) Section C - Response to Excursions or Exceedences contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature average below the three hour average specified by the catalyst manufacturer for VOC, CO and formaldehyde control or as established in the most recent compliance stack test is not considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

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

D.7.17 Record Keeping Requirement

(a) In order to document the compliance status with Conditions D.7.1, D.7.2, D.7.3, D.7.4, D.7.5, D.7.6 and D.7.7, the Permittee shall maintain monthly records of the amount and type of fuel combusted in the combined cycle combustion turbines.

(b) To document the compliance status with Condition D.7.2 - H_2SO_4 PSD BACT, the Permittee shall maintain the monthly vendors records of the fuel sulfur content of the natural gas combusted in the turbines and the associated duct burners.

(c) To document the compliance status with Condition D.7.6 (b) - GHGs PSD BACT, the Permittee shall maintain monthly records of the CO_{2e} emissions.

(d) To document the compliance status with the emission limits in Condition D.7.7 - Hazardous Air Pollutants (HAPs) minor Limits, the Permittee shall maintain monthly records of the formaldehyde emissions.

(e) To document compliance with Condition D.7.8 - Startup and Shutdown Limitations for Combustion Turbines, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup, shutdown) with supporting operational data;

(2) The total number of minutes for startup and shutdown operation per event; and

(3) Records shall be maintained at any time the unit is off-line.

(4) The CEMS data, fuel flow meter data, and/or Method 19 calculations used to determine the mass emissions rate corresponding to each startup and shutdown operating period.

(f) To document the compliance status with Condition D.7.14 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall record the output of the continuous monitoring systems and shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(g) In the event that a breakdown of the NOx or O_2 continuous emission monitoring system (CEMS) occurs in Condition D.7.14 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(h) To document the compliance status with Conditions D.7.14 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain the monthly records of the NOx emissions from each of the combined cycle combustion turbines EU-1 and EU-2 based upon the CEM data.

(i) In order to document the compliance status with Condition D.7.16 - Oxidation Catalyst Parametric Monitoring, the Permittee shall maintain continuous temperature records (on a three- (3-) hour average basis) for each oxidation catalyst to demonstrate compliance.

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

D.7.18 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.7.6(b), D.7.7, D.7.8(h), D.7.8(i) and D.7.8(j) shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(l) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

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

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

D.8.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The PM, $PM_{2.5}$ and PM_{10} emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.005 lb/MMBtu and 0.4 lbs/hour, based on a 3-hr average period through the use of good combustion practices and fuel specification.

D.8.2 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

(a) The H_2SO_4 emissions from the auxiliary boiler, identified as EU-3 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

D.8.3 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The CO emissions from the Auxiliary Boiler (EU-3) operation shall not exceed 0.083 lb/MMBtu and 6.5 lbs/hr, based on a 3 - hour average through the use of advanced ultra -low NOx burner.

D.8.4 VOC PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The VOC emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.42 lbs/hr, based on a 3-hr average period through the use of advanced ultra - low NOx burner.

D.8.5 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

(a) The NOx emissions from the Auxiliary Boiler, identified as EU-3 shall be controlled by Low NOx Burners with Flue Gas Recirculation.

(b) The NOx emissions shall be limited to less than 0.011 lb/MMBtu and 0.87 pounds per hour, based on a 3-hour average period.

D.8.6 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The GHGs BACT for the Auxiliary Boiler shall be as follows:

(a) Operating and Maintenance (O&M) Practices;

(b) Combustion Turning;

(c) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(d) The boiler will be equipped with an economizer;

(e) The boiler will be equipped with a condensate return system (recovery);

(f) Steam and hot lines will be insulated; and

(g) Boiler designed for 80% thermal efficiency (HHV).

(h) The total CO_2e emissions for Auxiliary Boiler shall be limited to less than 40,639 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

D.8.7 Startup, Shutdown and Other Opacity Limits [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (a) (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the applicable opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable opacity limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period.

(b) If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(a) or (b), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

Compliance Determination Requirements

D.8.8 Nitrogen Oxide Control

In order to ensure compliance with Condition D.8.5 - NOx PSD BACT, the Low NOx Burners with Flue Gas Recirculation shall be installed and utilized at all times that the auxiliary boiler is in operation.

D.8.9 H_2SO4 Compliance Determination Requirements [326 IAC 2-2]

In order to ensure compliance with Condition D.8.2, the Permittee shall maintain a record of the monthly average sulfur content of the natural gas based on vendor data.

D.8.10 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.8.1 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.8.3 - CO PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct CO emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.8.4 - VOC PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) In order to demonstrate compliance with Condition D.8.5 - NOx PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct NOx emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) In order to demonstrate compliance with Condition D.8.6(h) – GHGs PSD BACT, within sixty (60) days of reaching maximum capacity but no later than 180 days after initial startup, the Permittee shall perform thermal efficiency testing of the auxiliary boiler, identified as EU-3 utilizing methods approved by the Commissioner. These tests shall be conducted once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.8.11 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.8.6(h), the following equation shall be used to determine the CO_2e emissions from the Auxiliary Boiler:

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

Where:
Fuel Usage (mmscf/month) = monthly auxiliary boiler fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas, or vendor data, if available
CO_2 EF (lb/mmbtu) = 117 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = 0.0022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C)

for natural gas
N_2O EF (lb/mmbtu) = 0.00022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.8.12 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.8.1, D.8.2, D.8.3, D.8.4, D.8.5, D.8.6 and D.8.11, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the auxiliary boiler.

(b) To document the compliance status with Condition D.8.2 - H_2SO_4 PSD BACT, the Permittee shall maintain the monthly vendor records of the fuel sulfur content of the natural gas combusted in the auxiliary boiler.

(c) To document the compliance status with Condition D.8.6(h) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_{2e} emissions from the auxiliary boiler.

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

D.8.13 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.8.6(h) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(m) One (1) natural gas fired Dew Point Heater, identified as emission unit EU-4, permitted in 2013, with a rated heat input capacity of 20.8 MMBtu/hr exhausting to stack S-4.

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

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

D.9.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Dew Point Heater, identified as EU-4 shall be limited to less than 0.0072 lb/MMBtu and 0.15 lbs/hr, based on a 3-hr average period through the use of good combustion practices and fuel specification.

D.9.2 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

(a) The H_2SO_4 emissions from the dew point heater, identified as EU-4 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

D.9.3 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

The CO emissions from the Dew Point Heater (EU-4) operation shall not exceed 0.082 lb/MMBtu and 1.7 lbs/hr, based on a 3 - hour average through the use of good combustion and low NOx burners.

D.9.4 VOC PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

The VOC emissions from the Dew Point Heater, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.11 lbs/hr, based on a 3-hr average period through the use of good combustion and low NOx burners.

D.9.5 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

(a) The NOx emissions from the Dew Point Heater, identified as EU-4 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(b) The NOx emissions shall be limited to less than 0.032 lb/MMBtu and 0.67 pounds per hour, based on a 3-hr average period.

D.9.6 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

(a) The good engineering design and Combustion Practices.

(b) The use of only natural gas.

(c) The total CO_2e emissions for Dew Point Heater shall be limited to less than 10,659 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance Determination Requirements

D.9.7 Nitrogen Oxide Control

In order to ensure compliance with Condition D.9.5 - NOx PSD BACT, the low NOx burner shall be installed and utilized at all times that the dew point heater, identified as EU-4 is in operation.

D.9.8 Compliance Determination Requirements [326 IAC 2-2]

In order to determine compliance status with Conditions D.9.1 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.9.2 - H_2SO_4 PSD BACT, the Permittee shall only use natural gas in the dew point heater EU-4.

D.9.9 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.9.6(c), the following equation shall be used to determine the CO_2e emissions from the dew point heater, identified as EU-4:

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

Where:
Fuel Usage (mmscf/month) = monthly dew point heater usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas, or vendor data, if available
CO_2 EF (lb/mmbtu) = 117 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = 0.0022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = 0.00022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.9.10 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.9.1, D.9.2, D.9.3, D.9.4, D.9.5, and D.9.6, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the auxiliary boilers.

(b) To document the compliance status with Condition D.9.6(c) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_{2e} emissions from the auxiliary boilers.

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

D.9.11 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.9.6(c) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(c) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(d) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

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

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

D.10.1 PM, PM_{10}, $PM_{2.5}$, NOx, CO, H_2SO_4 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Emergency Generator, identified as emission unit EU-5 shall be as follows:

Emergency Diesel Generator, identified as (EU5):

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Generator, Identified as EU-5, shall not exceed 0.15 g/hp-hr, through the use of combustion design control.

(b) The H_2SO4 emissions;

1. The sulfur content of the fuel oil shall not exceed 15ppm.

(c) The CO emissions from the Emergency Generators, Identified as EU-5 shall not exceed 2.6 g/hp-hr through the use of combustion design controls and usage limitation.

(d) The NOx and VOC emissions from the Emergency Generator shall be limited to less than 4.80 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

(e) The GHGs BACT for the Emergency Diesel Generator, Identified as EU5 shall be as follows:

1. The use of a good engineering design; and

2. The total CO_2e emissions for Emergency Diesel Generator shall be limited to less than 605 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

D.10.2 PM, PM_{10}, $PM_{2.5}$, NOx, CO, H_2SO_4 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Emergency Fire Pump, identified as emission unit EU-6 shall be as follows:

Emergency Fire Pump Engine, identified as EU-6:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Fire Pump Engine shall not exceed 0.15 g/hp-hr through the use of combustion design control.

(b) H_2SO_4 BACT Limits

1. The sulfur content of the fuel oil shall not exceed 15ppm.

(c) The CO emissions from the Emergency Fire pump Engine shall not exceed 2.6 g/hp-hr through the use of combustion design controls and usage limitation.

(d) The NOx and VOC emissions from the Emergency Fire Pump Engine shall not exceed 3.0 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls and usage limitation.

(e) The GHGs BACT for the Emergency Diesel Generator, Identified as EU-6 shall be as follows:

1. The use of a good engineering design; and

2. The total CO_2e emissions for Firewater Pump Engine shall be limited to less than 158 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance Determination Requirements

D.10.3 Greenhouse Gases (GHGs) Calculations

(a) To determine the compliance status with Condition D.10.1(e)(2), the following equation shall be used to determine the CO_2e emissions from the Emergency Diesel Generator (EU-5):

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

Where:

Fuel Usage (gal/month) = monthly emergency generator fuel usage data from company records
Heat Content (mmbtu/gal) = standard value in AP-42 for diesel fuel, or vendor data, if available
CO_2 EF (lb/mmbtu) = 163 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CH_4 EF (lb/mmbtu) = 0.00661 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
N_2O EF (lb/mmbtu) = 0.00132 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

(b) To determine the compliance status with Condition D.10.2(g)(3), the following equation shall be used to determine the CO_{2e} emissions from the Emergency Fire Pump Engine (EU-6):

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

N_2O EF (lb/mmbtu) x N_2O GWP)] x 1/2000 (ton/lb)

Where:

Fuel Usage (gal/month) = monthly fire pump engine fuel usage data from company records
Heat Content (mmbtu/gal) = standard value in AP-42 for diesel fuel, or vendor data, if available
CO_2 EF (lb/mmbtu) = 163 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CH_4 EF (lb/mmbtu) = 0.00661 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
N_2O EF (lb/mmbtu) = 0.00132 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.10.4 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.10.1(b) and D10.2(b), the Permittee shall maintain monthly records of the percent sulfur content of the fuel used in the emergency diesel engine and the fire pump engine.

(b) To document compliance with Conditions D.10.1(e) and D.10.2(e), the Permittee shall maintain monthly records of hours of operation of the emergency diesel engine and the fire pump engine.

(c) To document the compliance status with Conditions D.10.1(e)(2), D.10.2(e)(2) and D.10.3, the Permittee shall maintain records of the total amount of fuel used each month in the emergency diesel engine and fire pump engine and the total CO_{2e} emissions from the emergency diesel engine and fire pump engine.

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

D.10.5 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.10.1(e)(2) and D.10.2(e)(2) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(e) One (1) evaporative cooling tower, identified as emission unit U-7, rated with a circulation rate of 192,000 gpm to provide non-contact cooling water to the steam turbine condenser, permitted in 2013, and equipped with high efficiency drift eliminators.

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

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

D.11.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the cooling water, identified as EU-7 shall be as follows:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Tower, identified as U-7 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and maximum total dissolved solids (TDS) shall be less than 5000 ppm.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Tower shall be less than 2.4, 1.5 and 0.005 pounds per hour, respectively.

Compliance Determination

D.11.2 PM, PM_{10} and $PM_{2.5}$ Control

(a) In order to ensure compliance with Conditions D.11.1 - PM and PM_{10} and $PM_{2.5}$ PSD BACT, the high efficiency drift eliminators for particulate control shall be in operation and control emissions from each cooling tower at all times that the cooling towers are in operation.

(b) The Permittee shall perform monthly tests of the blow-down water quality using EPA-approved method. This monthly test shall not be required for any 30-day period in which the wet cooling tower is not in operation, provided that the Permittee maintains a log of wet cooling tower operation.

(c) The Permittee shall calculate the PM, PM_{10}, and $PM_{2.5}$ emission rates using an equation based on the TDS and water circulation rate using the following formula.

$$E = (c \times T \times Q \times 8.34 \times 60 \times DR) / 10^6$$

Where:

E = mass emission rate in lbs/hr for PM, PM_{10} and $PM_{2.5;}$
c = particle size fraction (c=1 for PM; 0.635 for PM_{10} and 0.00213 for $PM_{2.5}$);
T = Total Dissolved Solids, mg/l;
Q = Cooling tower circulation rate, gallons/min; and
DR = Drift rate (assumed to be 0.0005% based on design).

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

D.11.3 Record Keeping Requirements

(a) To document the compliance status with Condition D.11.1, the Permittee shall maintain a log that contains the date and result of each blow-down water quality test and resulting mass rate. This log shall be maintained onsite for a minimum of five years and shall be provided to EPA and IDEM upon request.

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

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(f) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit F-1, permitted in 2013, with fugitive emissions controlled by full enclosure.

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

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

D.12.1 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Electrical Circuit Breakers, identified as SF6 shall be as follows:

(1) The use of totally enclosed pressure system with a design leak rate of 0.5% by weight and a density alarm for leak detection.

(2) The total SF_6 emissions from all the circuit breakers shall not exceed 59.8 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities
(g) Fugitive equipment leaks from the natural gas supply lines, identified as F-2.
(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

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

D.13.1 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Fugitive equipment leaks shall be as follows:

The BACT for fugitive GHG emissions shall be use of Auditory, Visual, and Olfactory (AVO) Monitoring program for methane leaks.

SECTION D.14 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(h) Three (3) Turbine Lube Demister Vents, permitted in 2013.

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

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

D.14.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Turbine Lube Oil Demister Vents shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents shall be the use of good design and operating practices.

SECTION E TITLE IV CONDITIONS

Oris Code: 991

Title IV Source Description:

(a) Two (2) no. 2 fuel oil fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) for control of NO_X emissions, which was voluntarily installed and is not required to operate. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

<u>The New Combined Cycle Combustion Turbine Generation Facility Emission Units:</u>

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

(The information contained in this box is descriptive information and does not constitute enforceable conditions.)

Acid Rain Program

E.1.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21] [40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78. The Acid Rain permit for this source is attached to this permit as Attachment A, and is incorporated by reference.

E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

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

New Source Performance Standards (NSPS) Requirements [326 IAC 12][40 CFR 60, Subpart KKKK]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the two (2) natural gas combustion turbines EU-1 and EU-2 and two (2) duct burners associated with the heat recovery steam generators, except as otherwise specified in 40 CFR Part 60, Subparts KKKK.

E.2.2 New Source Performance Standards for Stationary Combustion Turbines Requirements [40 CFR Part 60, Subpart KKKK] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart KKKK, the Permittee shall comply with the provisions of New Source Performance Standards for Stationary Combustions Turbines, which are incorporated by reference as 326 IAC 12, for the two (2) natural gas combustion turbines EU-1 and EU-2 and two (2) duct burners associated with the heat recovery steam generators as specified as follows:

1. 40 CFR 60.4300
2. 40 CFR 60.4305
3. 40 CFR 60.4320
4. 40 CFR 60.4330(a)(1) or (2)
5. 40 CFR 60.4333
6. 40 CFR 60.4340(b)(1)
7. 40 CFR 60.4345
8. 40 CFR 60.4350(a)-(e), (f)(1)-(2), (h)
9. 40 CFR 60.4360
10. 40 CFR 60.4365
11. 40 CFR 60.4370(b), (c)
12. 40 CFR 60.4375(a)
13. 40 CFR 60.4380(b)
14. 40 CFR 60.4385(a), (c)
15. 40 CFR 60.4395
16. 40 CFR 60.4400(a), (b)(2), (b)(4)-(6)
17. 40 CFR 60.4405
18. 40 CFR 60.4415
19. 40 CFR 60.4420

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(l) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

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

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

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the natural gas fired auxiliary boiler, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

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

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

1. 40 CFR 60.40c(a)-(d)
2. 40 CFR 60.41c
3. 40 CFR 60.48c(a)(1), (3)
4. 40 CFR 60.48c(g),(i)

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(d) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

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

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

E.4.1 General Provisions Relating to NSPS IIII [326 IAC 12][40 CFR Part 60, Subpart A]

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

E.4.2 Standards of Performance for Stationary Compression Ingnition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

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

The emergency fire pump engine is subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(ii)
2. 40 CFR 60.4202(d)
3. 40 CFR 60.4205(c)
4. 40 CFR 60.4206
5. 40 CFR 60.4207
6. 40 CFR 60.4211(a), (c)
7. 40 CFR 60.4218
8. 40 CFR 60.4219

The emergency diesel generator is subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(i)
2. 40 CFR 60.4202(a)(2)
3. 40 CFR 60.4205(b)
4. 40 CFR 60.4206
5. 40 CFR 60.4207
6. 40 CFR 60.4211(a), (c)
7. 40 CFR 60.4218
8. 40 CFR 60.4219

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(d) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

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

National Emissions Standard for Hazardous Air Pollutants [326 IAC 20] [40 CFR 63, Subpart ZZZZ]

E.4.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [326 IAC 20-1][40 CFR Part 63, Subpart A]

Pursuant to 40 CFR 63.6590, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 for the affected source, as specified in Appendix A of 40 CFR Part 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR 63 Subpart ZZZZ*.*

E.4.2 National Emissions Standard for Hazardous Air Pollutants for stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ][326 IAC 20-82-1]

Pursuant to CFR Part 63, Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR Part 63.6590, for the affected source, as specified as follows:

1. 40 CFR 63.6590
2. 40 CFR 63.6645

SECTION F RESERVED

SECTION G Clean Air Interstate Rule (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

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CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

(a) Two (2) no. 2 fuel oil fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) for control of NO_X emissions, which was voluntarily installed and is not required to operate. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

<u>The New Combined Cycle Combustion Turbine Generation Facility Emission Units:</u>

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

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

G.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)] [326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-1-2, 326 IAC 24-2-2, and 326 IAC 24-3-2.

G.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]

(a) The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall operate each source and unit in compliance with this CAIR permit.

(b) The CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units subject to this CAIR permit are Units 1, 2, 3, 4, 5 and 6.

G.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall comply with the applicable monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source with the CAIR NO_X emissions limitation under 326 IAC 24-1-4(c), CAIR SO_2 emissions limitation under 326 IAC 24-2-4(c), and CAIR NO_X ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition G.4.1, Nitrogen Oxides Emission Requirements, Condition G.4.2, Sulfur Dioxide Emission Requirements, and Condition G.4.3, Nitrogen Oxides Ozone Season Emission Requirements.

G.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 326 IAC 24-1-11.

(b) A CAIR NO_X unit shall be subject to the requirements under 326 IAC 24-1-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-1-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X allowance shall not be deducted for compliance with the requirements under 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(d) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X annual trading program. No provision of the CAIR NO_X annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in this CAIR permit.

G.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR SO_2 unit shall be subject to the requirements under 326 IAC 24-2-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-2-4(c)(2), and for each control period thereafter.

(c) A CAIR SO_2 allowance shall not be deducted for compliance with the requirements under 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(d) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

(e) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 trading program. No provision of the CAIR SO_2 trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR SO_2 allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in this CAIR permit.

G.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of the each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit at the source shall hold, in the source's compliance account, CAIR NO_X ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.

(b) A CAIR NO_X ozone season unit shall be subject to the requirements under 326 IAC 24-3-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-3-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X ozone season allowance shall not be deducted for compliance with the requirements under 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X ozone season allowance was allocated.

(d) CAIR NO_X ozone season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.

(e) A CAIR NO_X ozone season allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X ozone season trading program. No provision of the CAIR NO_X ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X ozone season allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR NO_X ozone season allowance to or from a CAIR NO_X ozone season source's compliance account is incorporated automatically in this CAIR permit.

G.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]

(a) The owners and operators of a CAIR NO_X source and each CAIR NO_X unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation shall do the following:

(1) Surrender the CAIR NO_X allowances required for deduction under 326 IAC 24-1-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-1-4, the Clean Air Act (CAA), and applicable state law.

(b) The owners and operators of a CAIR SO_2 source and each CAIR SO_2 unit that emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation shall do the following:

(1) Surrender the CAIR SO_2 allowances required for deduction under 326 IAC 24-2-8(k)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-2-4, the Clean Air Act (CAA), and applicable state law.

(c) The owners and operators of a CAIR NO_X ozone season source and each CAIR NO_X ozone season unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X ozone season emissions limitation shall do the following:

(1) Surrender the CAIR NO_X ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-3-4, the Clean Air Act (CAA), and applicable state law.

G.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

(a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

(d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program or to demonstrate compliance with the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

This period may be extended for cause, at any time before the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

G.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall submit the reports required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the information 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

(d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the information shall be submitted to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

G.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]

The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall be liable as follows:

(a) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall meet the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, respectively.

(b) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source.

(c) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit or the CAIR designated representative of a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall also apply to the owners and operators of such unit.

G.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]

No provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

G.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-1-6, 326 IAC 24-2-6, and 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), 326 IAC 24-3-6(f)(3), each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source, including all CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program concerning the source or any CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source.

(b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source choose to designate an alternate CAIR designated representative.

Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), 326 IAC 24-3-6(f)(3), whenever the term "CAIR designated representative" is used, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

PART 70 OPERATING PERMIT CERTIFICATION

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Mailing Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify): ____________________

☐ Report (specify): ____________________

☐ Notification (specify): ____________________

☐ Affidavit (specify): ____________________

☐ Other (specify): ____________________

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Signature:
Printed Name:
Title/Position:
Phone:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE BRANCH

100 North Senate Avenue
MC 61-53, IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: 317-233-0178
Fax: 317-233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Mailing Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004

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

☐ This is an emergency as defined in 326 IAC 2-7-1(12)
- The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile within two (**2**) days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

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

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

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

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? ☐ Y ☐ N Describe: 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: ____________________

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
Part 70 Quarterly Report

Source Name:	Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address:	4040 Blue Bluff Road, Martinsville, IN 46151
Mailing Address:	4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.:	T 109-26292-00004
Facility:	Units 1, 2, and PR-10
Parameter:	SO_2 Emissions
Limit:	Shall not exceed the pound per million Btu (lb/MMBtu) limit, demonstrated using a calendar month average

YEAR: _____

Emission Unit	Limit (lb/MMBtu)	SO_2 Emissions (lb/MMBtu)		
		Month:	Month:	Month:
Unit 1	0.37			
Unit 2	0.37			
Unit PR-10	0.5			

☐ No deviation occurred in this quarter.

☐ Deviations occurred in this quarter.
Deviation has been reported on: ____________________

Submitted By: ______________________________

Title/Position: ______________________________

Signature: ______________________________

Date: ______________________________

Phone: ______________________________

Attach a signed certification to complete this report.

Note: **The Part 70 quarterly reporting form shall no longer apply to the distillate fuel oil fired generator, identified as PR-10 and the two No. 2 fuel oil fired boilers identified as Units 1 and 2 after the emission units have been shut down and decommissioned.**

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbines EU-1 - EU-2
Parameter: NOx Emissions
Limit: shall not exceed 68 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

QUARTER : **YEAR:** _______________

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

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbines EU-1 - EU-2
Parameter: CO Emissions
Limit: shall not exceed 565 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

QUARTER : **YEAR: _______________**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: ______________________________________
Title / Position:______________________________________
Signature:____
Date: ____
Phone: ________________________________

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbines EU-1 - EU-2
Parameter: VOC Emissions
Limit: shall not exceed 146 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR: _______________**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: _______________________________________
Title / Position: _____________________________________
Signature: ____
Date: ____
Phone: ____

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbine EU-1 - EU-2
Parameter: CO_2e
Limit: shall not exceed 2,649,570 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR: _______________**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: _______________________________________
Title / Position:_______________________________________
Signature:_______________________________________
Date: _______________________________________
Phone: ____

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

Part 70 Quarterly Report

Source Name:	Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address:	4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.:	T 109-26292-00004
Facility:	Auxiliary Boiler EU-3
Parameter:	CO_2e
Limit:	shall not exceed 40,639 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR: _______________**

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

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name:	Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address:	4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.:	T 109-26292-00004
Facility:	Dew Point Heater EU-4
Parameter:	CO_2e
Limit:	shall not exceed 10,569 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR:** ________________

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

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Emergency Generator EU-5
Parameter: CO_2e
Limit: shall not exceed 605 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR: ______________**

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

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name:	Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address:	4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.:	T 109-26292-00004
Facility:	Fire Pump Engine EU-6
Parameter:	CO2e
Limit:	shall not exceed 157.5 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR: _______________**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: _______________________________________
Title / Position:_____________________________________
Signature:____
Date: ____
Phone: ____

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbines EU-1 - EU-2
Parameter: Single HAPs Emissions (Formaldehyde)
Limit: less than 9 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR: _______________**

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

☐ **No deviation occurred in this quarter.**

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

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name:	Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address:	4040 Blue Bluff Road, Martinsville, IN 46151
Mailing Address:	4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.:	T 109-26292-00004

Months: ________ to ________ Year: _______

Page 1 of 2

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

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

Form Completed By: ____

Title/Position: ____

Date: ____

Phone: ____

Attach a signed certification to complete this report.

Attachment A to a PSD/SSM/Part 70 Operating Permit

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

Source Name:	**IPL Eagle Valley Generating Station**
Source Location:	**4040 Blue Bluff Road, Martinsville, Indiana, 46151**
County:	**Morgan**
SIC Code:	**4911**
Operation Permit No.:	**T109-26292-00004**
Operation Permit Issuance Date:	**December 2, 2008**
Significant Source Modification No.:	**109-32471-00004**
Significant Permit Modification No.:	**109-32476-00004**
Permit Reviewer:	**Josiah Balogun**

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

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

§ 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 formationsbeneath the earth's surface, of which the principal constituent is methane; or

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

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

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

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

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

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

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

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

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

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

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

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

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

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

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

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

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

§ 60.42c Standard for sulfur dioxide (SO_2).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.43c Standard for particulate matter (PM).

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

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

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

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

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

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

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

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

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

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

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

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

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

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

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

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

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

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

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the

30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

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

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

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

Where:

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

Where:

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

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

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

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

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

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

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

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

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

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

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

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

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

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

§ 60.46c Emission monitoring for sulfur dioxide.

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

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

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

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

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

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

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

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

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

subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

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

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

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

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

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

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

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

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

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

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

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

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

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

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

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

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

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

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

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

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

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

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

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

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and

time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

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

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

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

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

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

§ 60.48c Reporting and recordkeeping requirements.

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

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

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

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

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

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

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

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

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar dates covered in the reporting period.

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

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

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

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

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

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

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

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

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

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

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

(1) For distillate oil:

(i) The name of the oil supplier;

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

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

(2) For residual oil:

(i) The name of the oil supplier;

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

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

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

(3) For coal:

(i) The name of the coal supplier;

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

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

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

(4) For other fuels:

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

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

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

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

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

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

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

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

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

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

Attachment B to a PSD/SSM/Part 70 Operating Permit

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII] [326 IAC 12]

Source Name:	**IPL Eagle Valley Generating Station**
Source Location:	**4040 Blue Bluff Road, Martinsville, Indiana, 46151**
County:	**Morgan**
SIC Code:	**4911**
Operation Permit No.:	**T109-26292-00004**
Operation Permit Issuance Date:	**December 2, 2008**
Significant Source Modification No.:	**109-32471-00004**
Significant Permit Modification No.:	**109-32476-00004**
Permit Reviewer:	**Josiah Balogun**

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40

CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the useful life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Reduce nitrogen oxides (NO_X) emissions by 90 percent or more, or limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (g/KW-hr) (1.2 grams per HP-hour (g/HP-hr)).

(2) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_X emissions by 90 percent or more, or limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section.

Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and §60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i= concentration of NO_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.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §60.4205. Non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder, must meet the applicable emission standards in §60.4204(c).

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI engines located in areas of Alaska not accessible by the Federal Aid Highway System should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) The Governor of Alaska may submit for EPA approval, by no later than January 11, 2008, an alternative plan for implementing the requirements of 40 CFR part 60, subpart IIII, for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. This alternative plan must be based on the requirements of section 111 of the Clean Air Act including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR part 60, subpart IIII. If EPA approves by rulemaking process an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel engines used in new stationary internal combustion engines subject to this paragraph.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

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

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder

and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)

	Model year(s)	NO_X+ NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)

56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_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,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.

			§60.17)	
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated	(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.

			by reference, see §60.17)	
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_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	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary,	(3) Method 4 of	(c) Measurements to

		measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	40 CFR part 60, appendix A	determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards	No	Requirements are specified in subpart IIII.

	and maintenance requirements		
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

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Attachment C to a PSD/SSM/Part 70 Operating Permit

Standards of Performance for Performance for Stationary Combustion Turbines [40 CFR Part 60, Subpart KKKK] [326 IAC 12]

Source Name:	**IPL Eagle Valley Generating Station**
Source Location:	**4040 Blue Bluff Road, Martinsville, Indiana, 46151**
County:	**Morgan**
SIC Code:	**4911**
Operation Permit No.:	**T109-26292-00004**
Operation Permit Issuance Date:	**December 2, 2008**
Significant Source Modification No.:	**109-32471-00004**
Significant Permit Modification No.:	**109-32476-00004**
Permit Reviewer:	**Josiah Balogun**

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

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

Introduction

§ 60.4300 What is the purpose of this subpart?

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

Applicability

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

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

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

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

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

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

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

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§ 60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

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

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

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

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

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

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

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

General Compliance Requirements

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

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

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

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

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

Monitoring

§ 60.4335 How do I demonstrate compliance for NOXif I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

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

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

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

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

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

§ 60.4340 How do I demonstrate continuous compliance for NOXif I do not use water or steam injection?

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

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

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

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_Xformation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_Xmode.

(iii) For any turbine that uses SCR to reduce NO_Xemissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_Xemission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

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

If the option to use a NO_XCEMS is chosen:

(a) Each NO_Xdiluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_Xdiluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_Xmonitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_Xemission rate for the hour.

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

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

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

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

For purposes of identifying excess emissions:

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

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

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

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

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

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

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical

energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq. 2)$$

Where:

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

$(Pe)_t$= electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$= electrical or mechanical energy output (if any) of the steam turbine in MW, and

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

Where:

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

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 10_6= conversion from Btu/h to MW.

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

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

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

Where:

E = NO_Xemission rate in lb/MWh,

$(NO_X)_m$= NO_Xemission rate in lb/h,

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

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

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

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

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

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

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

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

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

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

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

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

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

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

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

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

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

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

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

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

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

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

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

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

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

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

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

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

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

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

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

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

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

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

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

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

Reporting

§ 60.4375   What reports must I submit?

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

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

§ 60.4380   How are excess emissions and monitor downtime defined for

NOX?

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

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

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

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

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

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

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_Xemission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a “4-hour rolling average NO_Xemission rate” is the arithmetic average of the average NO_Xemission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_Xemission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_Xemission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a “30-day rolling average NO_Xemission rate” is the arithmetic average of all hourly NO_Xemission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_Xemissions rates for the preceding 30 unit operating days if a valid NO_Xemission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_Xconcentration, CO2 or O_2concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

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

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_Xemission controls:

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

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

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

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

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

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

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

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

(a) If you operate an emergency combustion turbine, you are exempt from the NO_Xlimit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_Xlimit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

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

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

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

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

(i) Measure the NO_Xconcentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_Xemission rate:

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

Where:

E = NO_Xemission rate, in lb/MWh

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

$(NO_X)_c$= average NO_Xconcentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

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

(ii) Measure the $NO_X$and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_Xemission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_Xemission rate in lb/MWh.

(2) Sampling traverse points for $NO_X$and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

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

(i) You may perform a stratification test for $NO_X$and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_Xconcentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2(or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_Xconcentration during the stratification test; or

(B) For turbines with a NO_Xstandard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_Xconcentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2(or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_Xstandard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_Xconcentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2(or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad (Eq.\ 6)$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

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

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

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

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

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

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

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

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

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

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for

New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850	96 ppm at 15 percent O_2 or 590 ng/J of useful

	MMBtu/h	output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2or 110 ng/J of useful output (0.86 lb/MWh).

Attachment D to a PSD/SSM/Part 70 Operating Permit

40 CFR 63, Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:

Source Name:	**IPL Eagle Valley Generating Station**
Source Location:	**4040 Blue Bluff Road, Martinsville, Indiana, 46151**
County:	**Morgan**
SIC Code:	**4911**
Operation Permit No.:	**T109-26292-00004**
Operation Permit Issuance Date:	**December 2, 2008**
Significant Source Modification No.:	**109-32471-00004**
Significant Permit Modification No.:	**109-32476-00004**
Permit Reviewer:	**Josiah Balogun**

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at

a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

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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:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

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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:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

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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:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

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Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{co2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Continuous Compliance Requirements

§ 63.6635   How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640   How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an

affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

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

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2 .

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2 .

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_x) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_x, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_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 1 a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE > 500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	**You must meet the following emission limitation, except during periods of startup . . .**	**During periods of startup you must . . .**
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1 b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

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

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2 a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE

>500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2 b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

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

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]

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:

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

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	a. Limit concentration of	

CI stationary RICE 300>HP≤500." is corrected to read "4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500.	CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually,	

	whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

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:

TABLE 2D TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	

5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually,	

	whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	

12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	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]

Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

TABLE 3 TO SUBPART ZZZZ OF PART 63—SUBSEQUENT PERFORMANCE TESTS

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]

2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

TABLE 4 TO SUBPART ZZZZ OF PART 63. REQUIREMENTS FOR PERFORMANCE TESTS

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Measure the O_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, or ASTM Method D6522-00 (Reapproved 2005).[a c]	(a) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005) [a b c] or Method 10 of 40 CFR part 60, appendix A	(a) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the	(1) Method 3 or 3A or 3B of	(a) measurements to

		inlet and outlet of the control device; and	40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	determine O_2concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a]provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) if using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	(a) measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location;	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the

		and		measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522-00 (2005),[a] [c] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] Incorporated by reference, see 40 CFR 63.14. You may also obtain copies from University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.

[c] ASTM-D6522-00 (2005) may be used to test both CI and SI stationary RICE.

[78 FR 6711, Jan. 30, 2013]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS

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	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

located at an area source of HAP		pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
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
		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.
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	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

more than 24 hours per calendar year		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:

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS

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	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

major source of HAP		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.
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.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or	a. Limit the concentration of formaldehyde in the	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below

reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	stationary RICE exhaust and not using oxidation catalyst or NSCR	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
		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.
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:

TABLE 7 TO SUBPART ZZZZ OF PART 63—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	i. Semiannually according to the requirements in § 63.6650(b).

		§ 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	
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).	i. Semiannually according to the requirements in § 63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5).
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	Subject of citation	Applies to	Explanation

provisions citation		subpart	
§ 63.1	General applicability of the General Provisions	Yes.	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	
§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No.	
§ 63.6(f)(1)	Applicability of standards	No.	
§ 63.6(f)(2)	Methods for determining compliance	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes.	
§ 63.6(j)	Presidential compliance exemption	Yes.	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at

			§§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes.	
§ 63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§ 63.7(f)	Alternative test method provisions	Yes.	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	

§ 63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes.	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
		Except that § 63.8(e) only applies as specified in § 63.6645.	
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§ 63.9(b)(1)-(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
		Except that § 63.9(b) only applies as specified in § 63.6645.	
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.

§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that § 63.9(g) only applies as specified in § 63.6645.	
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§ 63.10(b)(3)	Records of applicability determination	Yes.	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.

§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that § 63.10(e)(3)(i) (C) is reserved.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2 , or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 DEFINITIONS

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 SAFETY. [RESERVED]

6.0 EQUIPMENT AND SUPPLIES.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2 ; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ± 5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2 . When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 SAMPLE COLLECTION AND ANALYSIS

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ± 10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ± 3 percent, as instructed by the EC cell manufacturer.

9.0 QUALITY CONTROL (RESERVED)

10.0 CALIBRATION AND STANDARDIZATION

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 ANALYTICAL PROCEDURE

The analytical procedure is fully discussed in Section 8.

12.0 CALCULATIONS AND DATA ANALYSIS

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 PROTOCOL PERFORMANCE

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent *or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed*).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 POLLUTION PREVENTION (RESERVED)

15.0 WASTE MANAGEMENT (RESERVED)

16.0 ALTERNATIVE PROCEDURES (RESERVED)

17.0 REFERENCES

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Facility__________ Engine I.D.__________ Date______				
Run Type:	(_)	(_)	(_)	(_)
(X)	Pre-Sample Calibration	Stack Gas Sample	Post-Sample Cal. Check	Repeatability Check

.

Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
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Mean											
Refresh 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 Part 70 Operating Permit (TITLE V)

Source Background and Description

Source Name:	**IPL Eagle Valley Generating Station**
Source Location:	**4040 Blue Bluff Road, Martinsville, Indiana, 46151**
County:	**Morgan**
SIC Code:	**4911**
Operation Permit No.:	**T109-26292-00004**
Operation Permit Issuance Date:	**December 2, 2008**
PSD/Significant Source Modification No.:	**T109-32471-00004**
Significant Permit Modification No.:	**T109-32476-00004**
Permit Reviewer:	**Josiah Balogun**

On September 3, 2013, the Office of Air Quality (OAQ) had a notice published in The Martinsville Daily Reporter- Times in Martinsville, Indiana, stating that IPL Eagle Valley Generating Station has applied for a Significant Modification to their Part 70 Operating Title V Permit issued on December 2, 2008 relating to the proposed replacement of the current coal and oil fired electric generating units at Indianapolis Power and Light's (IPL's) Eagle Valley Generating Station (EVGS) with a state-of-the-art, highly efficient combined cycle combustion turbine electric generation facility. The notice also stated that OAQ proposed to issue a permit 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.

Comments Received

On September 30, 2013, IDEM, OAQ received comments from Angelique Oliger of IPL Eagle Valley Generating Station. The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice. Changes that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

The summary of the comments and IDEM, OAQ responses, including changes to the permit No. 109-26292-00004 (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comment 1: The proposed sulfur content limit for natural gas used in the combined cycle combustion turbines, auxiliary boiler and the dew point heater found in the proposed conditions D.7.2, D.8.2 and D.9.2 of the permit. The sulfur content of the natural gas is inherently low and expected to be consistently below the proposed limit of 0.75 gr S/100 scf, the actual sulfur content of the natural gas is not within our control hence compliance with this limit is not within our control. If in the future a spike in the sulfur content were to occur, we may have no choice but to cease operation in order to be in compliance which we do not believe to be in the best interest of the public. We would also point out that the proposed limit is only related to limiting Sulfuric Acid Mist (SAM) emissions for which there are not ambient air quality standards, nor is SAM a Hazardous Air Pollutant.

Therefore, we hereby request that these conditions from the permit be modified to require the use of pipeline natural gas, without a specific sulfur limitation. We also request that the related monitoring and recordkeeping requirements be removed from the permit.

Response 1: The H_2SO_4 emissions depend on the sulfur content of the natural gas which is 0.75 gr S/100 scf. The RBLC does not identify any facilities that have determined BACT to be the use of pipeline natural gas, because BACT in most cases is a numerical limit. While the use of pipeline natural gas can be used as an additional limit, the sulfur content of the natural gas, which is limited to 0.75 gr S/100 scf is the most appropriate limit for the H_2SO_4 emissions since this limit has been accepted and tested in other facilities nationwide.
No revisions to the draft permit are required as a result of this comment.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a PSD/Part 70 Significant Source and Permit Modification

Source Description and Location

Source Name:	**IPL Eagle Valley Generating Station**
Source Location:	**4040 Blue Bluff Road, Martinsville, Indiana, 46151**
County:	**Morgan**
SIC Code:	**4911**
Operation Permit No.:	**T109-26292-00004**
Operation Permit Issuance Date:	**December 2, 2008**
PSD/Significant Source Modification No.:	**T109-32471-00004**
Significant Permit Modification No.:	**T109-32476-00004**
Permit Reviewer:	**Josiah Balogun**

Existing Approvals

The source was issued Part 70 Operating Permit No. 109-26292-00004 on December 2, 2008. The source has since received the following approvals:

(a) Significant Permit Modification No. 109-27356-00004, issued on March 16, 2009; and

(b) Acid Rain Renewal Permit No.109-28085-00004, issued on October 19, 2009.

County Attainment Status

The source is located in Morgan County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Attainment effective October 19, 2007, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective federally July 11, 2013, for PM2.5.	

(a) Ozone Standards
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. Morgan County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Morgan County has been classified as attainment for $PM_{2.5}$. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011 the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. Morgan County was re-designated attainment County on July 11, 2013. Therefore, direct $PM_{2.5}$, NOx and SO_2 emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability – Entire Source section.

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

Fugitive Emissions

Since this source is classified as a power plant, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Source Status

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

Pollutant	**Emissions** (ton/yr)
PM	> 100
PM_{10}	> 100
$PM_{2.5}$	> 100
SO_2	> 100
VOC	< 100
CO	> 100
NO_X	> 100
GHGs as CO_2e	----
HAPs	
Single HAP	> 10
Total HAPs	> 25

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) These emissions are based upon Part 70 operating permit renewal No. 109-26292-00004, issued on December 2, 2008.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by IPL Eagle Valley Generating Station on October 31, 2012, relating to the proposed replacement of the current coal and oil fired electric generating units at Indianapolis Power and Light's (IPL's) Eagle Valley Generating Station (EVGS) with a state-of-the-art, highly efficient combined cycle combustion turbine electric generation facility. The proposed combined cycle facility would include two nominal 192.5 Mega Watt (MW) combustion turbines with steam waste heat recovery to drive a nominal 271 MW steam turbine generator. The new facility would have a total nominal capacity of 656 MW (net) at a fraction of the emissions of the present 340 MW coal and oil units. The exclusive fuel for the new combustion turbines will be natural gas. The following is a list of the proposed emission unit(s) and pollution control device(s):

(a) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

(b) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

(c) One (1) natural gas fired Dew Point Heater, identified as emission unit EU-4, permitted in 2013, with a rated heat input capacity of 20.8 MMBtu/hr exhausting to stack S-4.

Insignificant and Trivial Activities

The proposed new emissions units also include the following insignificant activities as defined in 326 IAC 2-7-1(21):

(a) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(b) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

(c) One (1) evaporative cooling tower, identified as emission unit U-7, with a rated circulation rate of 192,000 gpm to provide non-contact cooling water to the steam turbine condenser, permitted in 2013, and equipped with high efficiency drift eliminators.

(d) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit F-1, permitted in 2013, with fugitive emissions controlled by full enclosure.

(e) Fugitive equipment leaks from the natural gas supply lines, identified as F-2 controlled by a Leak Detection and Repair (LDAR) program.

(f) Three (3) Turbine Lube Demister Vents, permitted in 2013.

Enforcement Issues

There are no pending enforcement actions regarding this modification.

Emission Calculations

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

Permit Level Determination – Part 70

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

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

Increase in PTE Before Controls of the Modification	
Pollutant	**Potential To Emit** (ton/yr)
PM	135
PM_{10}	131
$PM_{2.5}$	125
SO_2	31
VOC	170
CO	660
NO_X	176
H_2SO_4	14
Mercury	0.00011
GHGs as CO_2e	2,703,157
Single HAPs (Formaldehyde)	15
Total HAPs	23

This source modification is subject to 326 IAC 2-7-10.5(g) because potential to emit PM, $PM_{10,}$ $PM_{2.5}$, VOC and NO_X are greater than 25 tons per year and potential to emit CO is greater than 100 tons per year. Therefore, this source modification shall be processed as PSD/Significant Source Modification pursuant to 326 IAC 2-7-10.5(g)(1), (4) and (7). Additionally, the modification will be incorporated into the Part 70 Operating Permit through a significant permit modification issued pursuant to 326 IAC 2-7-12(d), because the modification requires a case-by-case determination of an emission limitation to the existing Part 70 Operating Permit.

Permit Level Determination – PSD

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

Table 1

	Potential to Emit (Tons per year)												
Process	PM (tons)	PM_{10} (Tons)	$PM_{2.5}$ (tons)	SO_2	VOC	NOx	CO	GHGs as CO2e	H_2SO_4	Hg	SF6	Single HAP	Total HAPs
CT-1w/duct	8.4	8.4	8.4	1.8	84	9.5	310.5	153299	1.0	--	--	0.9	1.27
CT-1w/o duct	52.6	52.6	52.6	13.4		72.2		1171486	5.7	--	--	6.79	9.54
CT-2 w/duct	8.4	8.4	8.4	1.8	84	9.5	310.5	153299	1.0	--	--	0.9	1.27
CT-2 w/o duct	52.6	52.6	52.6	13.4		72.2		1171486	5.7	--	--	6.79	9.54
Aux. Boiler	1.7	1.7	1.7	0.5	1.8	3.8	28.5	40639	0.04	1.0E-4	--	0.028	0.72
Dew Point heater	0.66	0.66	0.66	0.13	0.48	2.92	7.47	10659	0.01	2.3E-5	--	0.007	0.17
Fire Pump	0.041	0.041	0.041	0.0015	0.03	0.8	0.72	157.47	--	--	--	1.0E-3	3.7E-3
Emer. Gen	0.16	0.16	0.16	0.01	0.10	4.7	2.63	605.32		--	--	1.0E-4	5.8E-3
Cooling Tower	10.5	6.7	0.02	--	--	--	--	--	--	--	--	--	--
Paved Roads/ Parking	0.216	0.043	0.011	--	--	--	--	--	--	--	--	--	--
Methane leaks	--	--	--	--	--	--	--	1466.9	--	--	--	--	--
Circuit Breaker	--	--	--	--	--	--	--	59.8	--	--	2.5E-3	--	--
3 Lube Oil Vents	0.229	0.229	0.229	--	--	--	--	--	--	--	--	--	--
Total Emissions	135.4	131.4	124.7	30.9	170.4	175.5	660.3	2703157	13.5	1.1E-4	2.5E-3	15.4	22.52
PSD Significant Level	**25**	**15**	**10**	**40**	**40**	**40**	**100**	**75,000**	**7**	**0.1**	**NA**	**NA**	**NA**

Since PM, PM10, $PM_{2.5}$, NOx, CO, H_2SO_4 and CO_2e are emitted in significant levels from the proposed modification, therefore, netting is triggered for these pollutants. Summation of contemporaneous emissions increases and decreases for the last 5 years prior to the modification have been considered in the analysis. See detailed netting analysis on Pages 1 through 21 of the emissions calculations spreadsheet.

SO_2, lead and Mercury are not emitted at significant level from the proposed modification. Therefore, netting was not triggered for these pollutants.

Table 2: Emission Reduction from shutdown of existing Units 1-6 (Based on 2010 and 2011 actual emissions)

	2010 and 2011 Actual Emissions (ton/year)											
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**VOC**	**CO**	**NO_X**	**GHGs as CO2e**	**H_2SO_4**	**Hg**	**Pb**	**Fl**
Boiler 1 (oil)	0.14	0.161	0.108	0.3	0.053	0.35	1.1	1598	0.024	2.9E-5	9.2E-5	
Boiler 2 (oil)	0.15	0.169	0.113	0.3	0.056	0.37	1.5	1671	0.026	3.1E-5	0.0126	
Boiler 3 (Coal)	38.83	160.32	146.7	4153	1.2	14.9	838	426151	9.37	2.5E-3	0.0261	4.5
Boiler 4 (Coal)	80.69	326.75	296.0		3.73	31.1			19.48	0.0052	0.0187	9.3
Boiler 5 (Coal)	84.55	251.63	219.5	6720	2.66	22.2	955	696768	13.93	0.0037	0.0445	6.7
Boiler 6 (Coal)	201.83	600.62	523.93		6.36	53			33.24	0.0088	0.102	15.9
Total emissions from Shutdown	432	1418	1255	11570	15.0	129.3	1782	1192644	76.1	0.021	0.108	38.5

Table 3: Projected Net Emissions Increase/Decreases based on 2010 and 2011 Actual Emissions

	Projected Net Emissions Increase/Decreases based on 2010 and 2011 Actual Emissions (Tons per year)											
Process	PM (tons)	PM_{10} (Tons)	$PM_{2.5}$ (tons)	SO_2	VOC	CO	NOx	GHGs as CO2e	H_2SO_4	Hg	Pb	Fl
New Emission Units PTE	135.4	131.4	124.7	30.9	170	660.3	175.5	2703157	13.5	1.1E-4	8.8E-5	0.00
Contemporaneous Emission Decrease (Shutdown of six boilers)	-432	-1418	-1255	-11570	-15	-129	-1782	-1192644	-80	-0.021	-0.11	-38.
Net Emission Increase	-300	-1286	-1130	-11539	155	531	-1606	1510513	-67	-0.021	-0.11	-38
PSD Significant Level	25	15	10	40	40	40	100	75,000	0.6	0.0004	0.1	NA

Federal Rule Applicability Determination

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the Part 70 major source threshold for the pollutant involved;

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

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

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new or modified emission unit involved:

CAM Applicability Analysis							
Emission Unit	**Control Device Used**	**Emission Limitation** (Y/N)	**Uncontrolled PTE** (ton/yr)	**Controlled PTE** (ton/yr)	**Part 70 Major Source Threshold** (ton/yr)	**CAM Applicable** (Y/N)	**Large Unit** (Y/N)
Combustion Turbine EU-1 (NOx)	Y	Y	> 100	< 100	100	Y	N
Combustion Turbine EU-1 (NOx)	Y	Y	> 100	< 100	100	Y	N
Combustion Turbine EU-1 (CO)	Y	Y	310.5	51	100	Y	N
Combustion Turbine EU-2 (CO)	Y	Y	310.5	51	100	Y	N
Combustion Turbine EU-1 (VOC)	Y	Y	> 100	< 100	100	Y	N
Combustion Turbine EU-2 (VOC)	Y	Y	> 100	< 100	100	Y	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to the combution turbines, idntified as EU-1 and EU-2 for CO and VOC emissions upon issuance of this Modification. A CAM plan has been incorporated in to this modification for CO and VOC emissions.

The combustion turbines meet the criteria of a pollutant-specific emission unit for CO, VOC, and NOx. IPL will use NOx CEMS, which meets the definition of a continuous compliance determination method in 40 CFR 64.1. Therefore, these turbines are exempt from the requirements of CAM for NOx emissions, pursuant to 40 CFR 64.2(b)(1)(iv).

The combustion turbines, auxiliary boiler, emergency generator and the fire pump, each has potential to emit regulated pollutants (uncontrolled) less than the major source thresholds. Therefore, the requirements of 40 CFR Part 64, CAM are not applicable to these emission units.

(b) The requirements of Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971, 40 CFR 60, Subpart D is not applicable to any sources in this project. The requirements of this rule apply to steam-generating units that commence construction, modification, or reconstruction after August 17, 1971, and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 73 MW (250 MMBtu/hour). The auxiliary boilers have a heat input capacity less than 250 MMBtu/hr, each; therefore, the auxiliary boilers are exempt from the requirements of NSPS Subpart D.

(c) The requirements of Standards of Performance for Electric Utility Steam Generating Units 40 CFR 60 Subpart Da, does not apply to the proposed HRSG units since 40 CFR 60.40Da(e) exempts heat recovery steam generators used with duct burners capable of combusting more than 250 MMBtu/hr heat input if the units meet the applicability requirements of and are subject to 40 CFR 60 Subpart KKKK.

This subpart also does not apply to the proposed auxiliary boiler because it cannot combust more than 250 MMBtu/hr.

(d) The requirements of Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units 40 CFR 60 Subpart Db, does not apply to the proposed HRSG units. 40 CFR 60.40b(i) exempts HRSGs associated with stationary combustion turbines that meet the requirements of subpart KKKK. Since the proposed HRSGs would be subject to the requirements of 40 CFR 60 Subpart KKKK, Subpart Db would not apply.

This subpart also does not apply to the proposed auxiliary boiler because it cannot combust more than 100 MMBtu/hr.

(e) The requirements of Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units apply to 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 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. This subpart does not apply to the proposed HRSG units. 40 CFR 60.40c(e) exempts HRSGs associated with stationary combustion turbines that meet the requirements of subpart KKKK.

(f) The requirements of the New Source Performance Standard, 40 CFR 60, Subpart GG, Standard of Performance for Stationary Gas Turbines apply to combustion turbines constructed or modified after October 3, 1977, with heat input equal to or greater than 10 MMBtu/hr [40 CFR 60.330]. However, NSPS GG has been supplanted by a newer subpart (NSPS KKKK) that exempts subject units from NSPS GG [40 CFR 60.4305(b)]. The combustion turbines are subject to the requirements of NSPS KKKK and are, therefore, exempt from the requirements of 40 CFR Subpart GG.

(g) The requirements of National Emission Standards For Hazardous Air Pollutants For Industrial Process Cooling Towers 40 CFR 63, Subpart Q, applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are located at major HAP sources. The proposed cooling towers will not use chromium based water treatment chemicals and the proposed combined cycle facility would not constitute a major source of HAPs. Therefore this subpart does not apply to the cooling towers.

(h) The requirements of National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines 40 CFR 63, Subpart YYYY applies to stationary combustion turbines located at Major Sources of HAPs. The proposed combined cycle plant will be an Area Source of HAPs following the shutdown of the existing boilers and with the proposed combined cycle project annual limitations on formaldehyde emissions. Therefore, this subpart would not apply.

(i) The requirements of Area Source MACT - National Emission Standards for Hazardous Air Pollutants – Industrial, Commercial, and Institutional Boilers at Area Sources 40 CFR Part 63 Subpart JJJJJJ regulates HAP emissions from industrial, commercial, and institutional boilers at area sources of HAP. Pursuant to 40 CFR 63.11195(e), gas-fired boilers are not subject to any requirements. Therefore, the proposed auxiliary boilers at SJEC will not have any applicable requirements under this standard.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD are not included in this permit. The requirements of this subpart apply to industrial, commercial or institutional boilers located at Major Sources of HAP emissions. The combined cycle plant would be an Area Source of HAPs following the shutdown of the existing boilers and the proposed annual limitations on formaldehyde emissions. Therefore, the requirements of 40 CFR 63, Subpart DDDDD are not included in the permit.

(k) The requirements of the New Source Performance Standard of Performance for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK applies to combustion turbines constructed, modified, or reconstructed after February 18, 2005, with heat input equal to or greater than 10 MMBtu/hr based on the higher heating value of the fuel [40 CFR 60.4305(a)]. The heat input from associated HRSGs and duct burners is not included in the applicability determination; however, the subpart applies to emissions from the combustion turbines, HRSGs, and duct burners if the heat input of the combustion turbines exceeds 10 MMBtu/hr. The proposed combustion turbines for this source have peak heat inputs greater than 10 MMBtu/hr. Therefore, the combustion turbines, HRSGs, and duct burners are subject to the requirements of 40 CFR 60, Subpart KKKK.

(1) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

The combustion turbines, HRSGs and duct burners are subject to the following Sections of 40 CFR Part 60, Subpart KKKK.

1. 40 CFR 60.4300
2. 40 CFR 60.4305
3. 40 CFR 60.4320
4. 40 CFR 60.4330(a)(1) or (2)
5. 40 CFR 60.4333
6. 40 CFR 60.4340(b)(1)
7. 40 CFR 60.4345
8. 40 CFR 60.4350(a)-(e), (f)(1)-(2), (h)
9. 40 CFR 60.4360
10. 40 CFR 60.4365
11. 40 CFR 60.4370(b), (c)
12. 40 CFR 60.4375(a)
13. 40 CFR 60.4380(b)
14. 40 CFR 60.4385(a), (c)
15. 40 CFR 60.4395
16. 40 CFR 60.4400(a), (b)(2), (b)(4)-(6)

17. 40 CFR 60.4405
18. 40 CFR 60.4415
19. 40 CFR 60.4420

(l) The requirements of the New Source Performance Standard, 40 CFR 60, Subpart Dc, Standard of Performance for Small -Commercial-Institutional Steam Generating Units, which is incorporated by reference as 326 IAC 12 NSPS, applies to steam generating units constructed or modified after June 9, 1989, with heat input equal to or greater than 10 MMBtu/hr but less than 100 MMBtu/hr [40 CFR 60.40c(a)]. The proposed project will include auxiliary boilers with a maximum heat input capacity of 79.3 MMBtu/hr. Since the auxiliary boilers combust natural gas to heat a heat transfer medium, the boilers meet the definition of steam generating units and are regulated by NSPS Dc.
Pursuant to 40 CFR 60.48c(g)(2), affected sources that combust only natural gas are required to record and maintain records of the amount of natural gas combusted during each calendar month. According to 40 CFR 60.48c(i), the monthly fuel usage records must be maintained for a minimum of two (2) years.

The following emission unit is subject to the following portions of Subpart Dc:

(1) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

The auxiliary boiler is subject to the following Sections of 40 CFR Part 60, Subpart Dc.

1. 40 CFR 60.40c(a)-(d)
2. 40 CFR 60.41c
3. 40 CFR 60.48c(a)(1), (3)
4. 40 CFR 60.48c(g),(i)

(m) The requirements of 40 CFR, Subpart IIII - Standard of Performance for Stationary Compression Ignition Internal Combustion Engines 40 CFR 60, apply to owners or operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, and that were manufactured after April 1, 2006, and are not fire pump engines, or were manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(1) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

The Emergency Fire Pump engines are subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(ii)
2. 40 CFR 60.4202(d)
3. 40 CFR 60.4205(c)
4. 40 CFR 60.4206
5. 40 CFR 60.4207
6. 40 CFR 60.4211(a), (c)
7. 40 CFR 60.4218
8. 40 CFR 60.4219

(1) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is

considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

The emergency diesel generator is subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(i)
2. 40 CFR 60.4202(a)(2)
3. 40 CFR 60.4205(b)
4. 40 CFR 60.4206
5. 40 CFR 60.4207
6. 40 CFR 60.4211(a), (c)
7. 40 CFR 60.4218
8. 40 CFR 60.4219

(n) The requirements of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engine 40 CFR 63, Subpart ZZZZ applies to stationary RICE at Area or Major Sources of HAPs and therefore, the emergency generator and fire pump would be subject to this subpart. However, pursuant to 40 CFR 63.6590(c)(1), a new or reconstructed RICE at an area source of HAPs would meet the requirements of this subpart by complying with 40 CFR 60 Subpart IIII. There are no further requirements under Subpart ZZZZ, including the requirement to submit an initial notification.

These emission units are subject to the following portions of Subpart ZZZZ:

(1) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(2) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

The emergency diesel generator and Emergency Fire Pump engines are subject to the following Sections of 40 CFR Part 63, Subpart ZZZZ.

1. 40 CFR 63.6590
2. 40 CFR 63.6645

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63 Subpart ZZZZ.

(o) 326 IAC 24 and 40 CFR Part 97, Clean Air Interstate Rule (CAIR):
The natural gas-fired combined cycle combustion turbines and heat recovery steam generators are subject to the Clean Air Interstate Rule (CAIR). This includes: the Nitrogen Oxides Annual Trading Program (326 IAC 24-1); the Sulfur Dioxide Trading Program (326 IAC 24-2; and Nitrogen Oxides Ozone Season Trading Program (326 IAC 24-3). These emission units are subject to these regulatory requirements because the proposed CTs will serve a generator rated at 25 MW or more and will produce electricity for sale.

(p) 326 IAC 21 and 40 CFR Part 72-78 Acid Rain Program
The Acid Rain Program (ARP) found at 40 CFR 72-78 applies to utility units. A utility unit is defined as a unit owned or operated by a utility that serves a generator in any state that produces electricity for sale. The CCCTs at the proposed facility are utility units subject to the ARP because the CCCTs will serve a generator rated at 25 MW or more and will produce electricity for sale. The proposed auxiliary boiler does not provide steam that subsequently generates electricity from the steam turbines; thus, the boiler cannot generate electricity for sale and are not subject to the ARP. The ARP requires pollutant monitors in addition to possession of SO_2 allowances for each ton of SO_2 emitted. Possession of the SO_2 allowances is not required until after the end of the year in which the SO_2 is emitted. Therefore, this source is subject to the requirements of 326 IAC 21.

State Rule Applicability Determination

326 IAC 2-2 (Prevention of Significant Deterioration)
This source is a major source for PSD because the potential to emit of one of the regulated pollutants are emitted at a rate greater than 100 tons per year and is in 1 of 28 source categories. The uncontrolled potential to emit of this modification is greater than 25 tons per year for PM, greater than 15 tons per year for PM10, greater than 40 tons per year for VOC, greater than 100 tons per year for CO and greater than 75,000 for CO_2. Therefore, this modification is subject to PSD review.

The “contemporaneous” emission decreases associated with the shutdown of the existing boilers and the net emissions increase associated with the proposed project, shows there is a “significant net emissions increase” for VOCs, CO and CO_2e only, and there will be significant reductions in the emissions for NOx, PM, PM_{10}, $PM_{2.5}$, and H_2SO_4. As such, the requirements of PSD would only apply to VOCs, CO and CO_2e. However, for this project, the source is electing to not utilize any credits for the shutdown of existing equipment and base PSD applicability on whether there is a “significant emission increase.” Therefore, this project is subject to PSD BACT for PM, PM_{10}, $PM_{2.5}$, H_2SO_4, VOCs, NOx, CO and CO_2e.

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the source shall be as follows:

Natural Gas-Fired Combined Cycle Combustion Turbines, identified as EU1 and EU2:

1. **The PM, PM_{10} and $PM_{2.5}$ emissions;**

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 16.8 pounds per hour, each and 0.0066 pounds per MMBtu, each with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(b) The PM and PM_{10} emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 13.9 pounds per hour, each and 0.0055 pounds per MMBtu, each without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(c) Pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

2. **The H_2SO_4 emissions;**

(a) The H_2SO_4 emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall be limited by restricting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

(b) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

3. **The CO emissions;**

(a) The CO emissions from the combined cycle combustion turbines shall be controlled by catalytic oxidation

(b) The CO emissions shall not exceed 2.0 ppmvd @15% O_2, based on a 3-hour average.

(c) Pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

4. **The VOC emissions;**

(a) The VOC emissions from the CCCTs shall be controlled by a catalytic oxidation

(b) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average.

(c) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average.

(c) Pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

5. **The NOx emissions;**

(a) The NOx emissions from the CCCTs shall be controlled by a Selective Catalytic Reduction and Dry Low NOx combustors.

(b) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hr average.

(c) Pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

6. **The GHGs BACT for the Combined Cycle Combustion Turbines identified as EU1 - EU2 shall be as follows;**

(a) The net heat rate shall not exceed 7,750 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(b) The total CO_{2e} emissions for combined cycle combustion turbines shall be limited to less than 2,649,570 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Startup and Shutdown Limitations for Combined Cycle Combustion Turbines

(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves consecutive CEMS data points in compliance with the primary BACT limits.

(b) Steady-state operating condition shall be defined as the period of time that the combustion turbine is operating in dry low NOx (premix) mode and in compliance with the primary BACT limit.

(c) A shutdown is defined as operation beginning when the combustion turbine exits dry low-NOx (premix) mode and ending with termination of continuous fuel flow to each turbine.

(d) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(e) Unit Offline is represented by the Unit on-line Time being 0.

(f) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown

For CO and NO_X, the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCTs. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor. Therefore, the source proposes to use the cold start emission totals, per CCCT as a short-term limit during startup/shutdown events, as follows:

CO - 3,390 lb/event

NOx - 429 lb/event

(g) The NO_X emissions from the combined cycle combustion turbines stacks shall not exceed 68 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(h) The CO emissions from the combined cycle combustion turbines stacks shall not exceed 565 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(i) The VOC emissions from the combined cycle combustion turbines stacks shall not exceed 146 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

Natural Gas-Fired Auxiliary Boilers, identified as EU3:

1. The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.005 lb/MMBtu and 0.4 lbs/hour, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

2. **The H_2SO_4 emissions;**

   (a) The H_2SO_4 emissions from the auxiliary boiler, identified as EU-3 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

3. The CO emissions from the Auxiliary Boiler (EU-3) operation shall not exceed 0.083 lb/MMBtu and 6.65 lbs/hr, each, based on a 3 - hour average through the use of advanced ultra -low NOx burner.

4. The VOC emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.42 lbs/hr, each, based on a 3-hr average period through the use of advanced ultra -low NOx burner.

5. **The NOx emissions;**

   (a) The NOx emissions from the Auxiliary Boilers, identified as EU-3 shall be controlled by Low NOx Burners with Flue Gas Recirculation.

(b) The NOx emissions shall be limited to less than 0.011 lb/MMBtu and 0.87 pounds per hour, based on a 3-hr average period.

6. **The GHGs BACT for the Auxiliary Boilers, identified as EU3 shall be as follows;**

(a) Operating and Maintenance (O&M) Practices;

(b) Combustion Turning;

(c) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(d) The boiler will be equipped with an economizer;

(e) The boiler will be equipped with a condensate return system (recovery);

(f) Steam and hot lines will be insulated; and

(g) Boiler designed for 80% thermal efficiency (HHV).

(h) The total CO_2e emissions for Auxiliary Boiler shall be limited to less than 40,639 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Dew Point Heater EU-4

1. The PM, PM_{10} and $PM_{2.5}$ emissions from the Dew Point Heater, identified as EU-4 shall be limited to less than 0.0072 lb/MMBtu and 0.15 lbs/hr, based on a 3-hr average period through the use of good combustion practices and fuel specification.

2. **The H_2SO_4 emissions;**

(a) The H_2SO_4 emissions from the dew point heater, identified as EU-4 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

3. The CO emissions from the Dew Point Heater (EU-4) operation shall not exceed 0.082 lb/MMBtu and 1.7 lbs/hr, based on a 3 - hour average through the use of good combustion and low NOx burners.

4. The VOC emissions from the Dew Point Heater, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.11 lbs/hr, based on a 3-hr average period through the use of good combustion and low NOx burners.

5. **The NOx emissions;**

(a) The NOx emissions from the Dew Point Heater, identified as EU-4 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(b) The NOx emissions shall be limited to less than 0.032 lb/MMBtu and 0.67 pounds per hour, based on a 3-hr average period.

6. **The GHGs BACT for the Dew Point Heater, identified as EU-4 shall be as follows;**

(a) The good engineering design and Combustion Practices.

(b) The use of only natural gas.

(c) The total CO_2e emissions for Dew Point Heater shall be limited to less than 10,659 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Emergency Diesel Generator, identified as EU5:

1. The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Generator, Identified as EU-5, shall not exceed 0.15 g/hp-hr, through the use of combustion design control.

2. **The H_2SO_4 emissions;**

   (a) The sulfur content of the fuel oil shall not exceed 15ppm.

3. The CO emissions from the Emergency Generators, Identified as EU-5 shall not exceed 2.6 g/hp-hr through the use of combustion design controls.

4. The NOx and VOC emissions from the Emergency Generator shall be limited to less than 4.80 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

5. The GHGs BACT for the Emergency Diesel Generator, Identified as EU5 shall be as follows:

   (a) The use of a good engineering design;

   (b) The total CO_2e emissions for Emergency Diesel Generator shall be limited to less than 605 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Emergency Fire Pump Engine, identified as EU6:

1. The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Fire Pump Engine shall not exceed 0.15 g/hp-hr through the use of combustion design control.

2. **The H_2SO4 emissions;**

   (a) The sulfur content of the fuel oil shall not exceed 15ppm.

3. The CO emissions from the Emergency Fire pump Engine shall not exceed 2.6 g/hp-hr through the use of combustion design controls.

4. The NOx and VOC emissions from the Emergency Fire Pump Engine shall not exceed 3.0 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

5. The GHGs BACT for the Emergency Diesel Generator, Identified as EU-6 shall be as follows:

   (a) The use of a good engineering design;
   (b) The total CO_2e emissions for Firewater Pump Engine shall be limited to less than 157.50 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Cooling Tower U-7:

1. **The PM, PM_{10} and $PM_{2.5}$ emissions;**

   (a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Tower, identified as U-7 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and maximum total dissolved solids (TDS) shall be less than 5000 mg/L.

   (b) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Tower shall be less than 2.4, 1.5 and 0.005 pounds per hour, respectively.

Electric Circuit Breaker (F-1):

1. The use of totally enclosed pressure system with a design leak rate of 0.5% by weight and a density alarm for leak detection.

2. The total CO_2e emissions for circuit breakers shall be limited to less than 59.80 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

The GHGs BACT for Fugitive Equipment Leaks shall be as follows;

1. The BACT for fugitive GHG emissions shall be use of Auditory, Visual, and Olfactory (AVO) Monitoring program for methane leaks.

Three (3) Turbine Lube Oil Demister Vents:

1. The PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents shall be the use of good design and operating practices.

Hazardous Air Pollutants (HAPs) Minor Limits
The source has the uncontrolled potential to emit greater than ten (10) tons per year for a single HAP (formaldehyde) and less than twenty-five (25) tons per year for a combination of HAPs, therefore:

The emission units shall be limited as follows:

(a) The combined cycle combustion turbines identified as EU-1 and EU-2, formaldehyde emissions shall be limited to less than nine (9.0) tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The formaldehyde emissions from the CCCTs shall be calculated by the following equation:

L (tons/month)= (7.1×10^{-4} x Qu + C x Qc)/2000 lbs/ton

Where:

L = 9 tons of (formaldehyde) per 12 month rolling period.

7.1×10^{-4} is the uncontrolled emission factor for formaldehyde (lbs/MMBtu)

Qu = 12- month rolling total heat input to the CT units (MMBtu) when the oxidation catalyst is not fully operational during startup and shutdown conditions

Qc = 12- month rolling total heat input to the CT units (MMBtu) when the oxidation catalyst is fully operational (includes heat input to duct burners).

C = is the controlled emission factor for formaldehyde (lbs/MMBtu), which would be based on stack test results of the CCCTs. Prior to stack testing the factor will be conservatively assumed to equal 60% of the uncontrolled emission factor.

Compliance with the above limits and requirements and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of formaldehyde and make the source an area source of HAPs.

326 IAC 1-7 (Actual Stack Height Provisions)
The stack height provisions in this rule apply to sources for which construction commenced after June 19, 1979 and that emit SO_2 or PM emissions in levels greater than 25 tons per year. The

combined cycle combustion turbine stacks, are subject to these requirements. As such, these stacks are subject to the height provisions listed in 326 IAC 1-7-3, which prohibits excessive concentrations of PM and SO_2.

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

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
The source is not subject to the requirements of 326 IAC 6-5 because the amounts of fugitive particulate matter emissions from paved roadways are less than 25 tons per year.

State Rule Applicability – Individual Facilities

326 IAC 3-5 (Continuous Monitoring of Emissions)
The natural gas-fired combined cycle combustion turbine, identified as units EU-1 and EU-2, are subject to the monitoring requirements of 326 IAC 3-5 because they are fossil fuel fired steam generators that have a heat input capacity of greater than 100 MMBtu per hour, each.
Pursuant to 326 IAC 3-5-1(b)(2)(C) and 326 IAC 3-5-1(a)(1), a continuous monitoring system shall be installed, calibrated, operate and maintain Nitrogen Oxide (NOx) and O_2 for each of the stacks, S-1 and S-2 in accordance with 326 IAC 3-5-2 and 326 IAC 3-5-3.

326 IAC 5-1-3 (Temporary Alternative Opacity Limitations)
Pursuant to 326 IAC 5-1-3 (a) (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the applicable opacity limitation established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable opacity limitation established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period.

If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(a) or (b), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

326 IAC 6-2-2 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-2 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the auxilliary boiler, identified as EU-3 and the duct burners shall not exceed 0.22 pounds per million Btu heat input (lb/MMBtu), each. This limitation was calculated using the following equation:

$$Pt = \frac{0.87}{Q^{0.16}}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
For these units, Q = 2542 + 2542 + 79.3 = 5163.3 MMBtu/hr.

However, 326 IAC 6-2-1(h) states that if a limitation established by this rule is inconsistent with a limitation required by the permit regulations, then the permit regulation limit will prevail. Since the BACT emissions limit is significantly more stringent than the above calculated limit, compliance with the BACT particulate matter limits renders the above rule 326 IAC 6-2-4 not applicable to this auxiliary boiler.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1(c), the particulate emission limitations for manufacturing processes contained in 326 IAC 6-3 do not apply to any of the emission units because particulate matter emission limitations established under 326 IAC 2-2-3 (PSD) are more stringent and are exempt from the requirements of this rule.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
(a) The emergency diesel generator and emergency fire pump engine are not subject to the requirements of 326 IAC 7-1.1 because each of them has the potential to emit SO_2 emissions less than 25 tons per year.

(b) The potential to emit SO_2 emissions from each of the heat recovery steam generators is less than 25 tons per year. Therefore, these units are not subject to the requirements of 326 IAC 7-1.1.

(c) The potential to emit SO_2 emissions from each of the combined cycle combustion turbines, identified as EU-1 and EU-2 is less than 25 tons per year. Therefore, these units are not subject to the requirements of 326 IAC 7-1.

326 IAC 8-1-6 (New facilities; general reduction requirements)
(a) This rule requires that new facilities (as of January 1, 1980), which have potential VOC emissions of greater than 25 tons per year, located anywhere in the state, which are not otherwise regulated by other provisions of 326 IAC 8, shall reduce VOC emissions using Best Available Control Technology (BACT). The two (2) combustion turbines, identified as EU-1 and EU-2 are subject to the requirements of 326 IAC 2-2-3 (PSD BACT), therefore, PSD BACT requirements will satisfy for the requirements of 326 IAC 8-1-6 at this source.

(b) This rule requires that new facilities (as of January 1, 1980), which have potential VOC emissions of 25 tons or more per year, located anywhere in the state, which are not otherwise regulated by other provisions of 326 IAC 8, shall reduce VOC emissions using Best Available Control Technology (BACT). The auxiliary boiler, dew point heater, emergency fire pump and emergency generator each have potential VOC emissions of less than 25 tons per year. Therefore, 326 IAC 8-1-6 does not apply to these facilities.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
This source is subject to 326 IAC 9-1 because it is a stationary source of CO emissions commencing operation after March 21, 1972 and has CO emissions of more than 100 tons per year. There are no applicable CO emission limits, under this state rule, established for this type of operation and the source is not proposing to install any of the source types regulated under this rule at the CCCT Facility.

326 IAC 2-2-4 (Air Quality Analysis Requirements)
Section (4)(a) of this rule, requires that the PSD application shall contain an analysis of ambient air quality in the area that the major stationary source would affect for pollutants that are emitted at major levels or significant amount. IPL has submitted an air quality analysis, which has been evaluated by IDEM's Technical Support and Modeling Section. See details in Appendix C.

NAAQS modeling for the appropriate time-averaging periods was conducted. OAQ modeling results are shown in Appendix C. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum modeled concentrations during the five years of modeling were below the NAAQS standards with the exception of the 1-hour NO_2 NAAQS. Additional air quality modeling was not required for the 24-hour PM_{10} and $PM_{2.5}$ and the annual $PM_{2.5}$ and NO_2 standards. The 1-hour NO_2 NAAQS modeling results shown in Table 5 of Appendix C had a violation of the 1-hour NO_2 standard of 100 parts per billion (ppb) or 188.7 ug/m^3. The highest 8th-high 1-hour NO_2 concentration averaged across five years was 419.7 ug/m^3 resulting in a total 1-hour NO_2 concentration of 487.6 ug/m^3 with a background concentration of 67.9 ug/m^3. The highest 8th-high maximum daily 1-hour NO_2 modeled concentration of 419.7 in Table 5 of Appendix C was adjusted from an actual modeled concentration of 524.6 ug/m^3 by using the NO_2/NO_x default ambient ratio of 0.8 (524.6 X 0.8 = 419.7) for a 1-hour concentration. The annual

NO_2 modeled concentration shown in Table 5 of Appendix C has been adjusted by the 0.75 default ambient ratio for NO_x to NO_2 conversion for an annual concentration.

326 IAC 2-2-5 (Air Quality Impact Requirements)
326 IAC 2-2-5(e)(1) of this rule, requires that the air quality impact analysis required by this section shall be conducted in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration processes required by this section shall be based upon the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models)*.

(2) Where an air quality impact model specified in the guidelines cited in subdivision (1) is inappropriate, a model may be modified or another model substituted provided that all applicable guidelines are satisfied.

(3) Modifications or substitution of any model may only be done in accordance with guideline documents and with written approval from U.S. EPA and shall be subject to public comment procedures set forth in 326 IAC 2-1.1-6.

Economic Growth

No impact from the economic growth is expected from the IPL Eagle Valley PSD permit major source modification and physical changes at the IPL Eagle Valley facility. The existing Martinsville, Indiana and Morgan County community will be able to adequately handle potential commercial growth associated with this future plant modification. An additional employment of 30 to 40 people is expected as a result of this facility modification.

Soils and Vegetation Analysis

A soils and vegetation analysis was performed by ERM to assess the impact of the criteria pollutant air emissions. Soil types in Morgan County include silt loam, clay loam, and sandy loam soils. Crops in Morgan County consist mainly of corn, soybeans, and wheat. Trees in Morgan County are mostly hardwoods such as maples and oaks. The results of the soils and vegetation analysis show the modeled impacts are well below the thresholds necessary to have an adverse impact on the surrounding soils and vegetation. The results of the soils and vegetation analysis are listed in the IPL Eagle Valley PSD Permit Application, section 8, page 26.

Federal Endangered Species Analysis

Federal and State endangered or threatened species are listed by the Indiana Department of Natural Resources; Division of Nature Preserves for Morgan County, Indiana and includes eight species of mussels, six species of birds, three species of reptiles, two species of bats, and one specie each of fish and amphibian. The mussels and birds listed are commonly found along major rivers and lakes while the bats are found near caves. The Martinsville Eagle Valley facility is not expected to have any additional adverse effects on the habitats of the endangered species other than that which has already occurred from the industrial and residential activities in the area. The endangered species of bats maintains habitats in caves and mines none of which are near the Martinsville facility. Federal and State endangered or threatened plants are listed by the Indiana Department of Natural Resources, Division of Nature Preserves and include no threatened or endangered species of plants in the Morgan County area of central Indiana.

326 IAC 2-2-6 (Increment Consumption Requirements)
326 IAC 2-2-6(a) requires that any demonstration under section 5 of this rule shall demonstrate that increased emissions caused by the proposed major stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentration of sulfur dioxide, particulate matter, and nitrogen dioxide indicated in subsection (b)(1) of this rule.

326 IAC 2-2-7 (Additional Analysis, Requirements)
326 IAC 2-2-7(a) requires an analysis of the impairment to visibility, soils and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source was performed. See detailed analysis in Appendix C.

326 IAC 2-2-8 (Source Obligation)
(1) Pursuant to 2-2-8(1), approval to construct shall become invalid if construction is not commenced within eighteen (18) months after receipt of the approval, if construction is discontinued for a period of eighteen (18) months or more, or if construction is not completed within a reasonable time.

(2) Approval for construction shall not relieve the Permittee of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state, or federal law.

326IAC 2-2-10 (Source Information)
The Permittee has submitted all information necessary to perform an analysis or make the determination required under this rule.

326 IAC 2-2-12 (Permit Rescission)
The permit issued under this rule shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or section 8 of this rule.

Compliance Determination and Monitoring Requirements

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

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

The Compliance Determination Requirements applicable to this modification are as follows:

Testing Requirements

(a) Testing Requirements

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
Combined Cycle Combustion Turbine Units EU-1 and EU-2	With Duct Burner Without Duct Burner	60 days / no later than 180 days	PM, PM_{10} and $PM_{2.5}$	5 year	326 IAC 2-2-3
Combined Cycle Combustion Turbine Units EU-1 and EU-2	Oxidation Catalyst with Duct Burner	60 days / no later than 180 days	CO	5 year	326 IAC 2-2-3
Combined Cycle Combustion Turbine Units EU-1 and EU-2	Oxidation Catalyst with Duct Burner Oxidation Catalyst without Duct Burner	60 days / no later than 180 days	VOC	5 year	326 IAC 2-2-3
Combined Cycle Combustion Turbine Units EU-1 and EU-2	No control	60 days / no later than 180 days	CO_2 (Heat Rate Performance)	5 year	326 IAC 2-2-3
Combined Cycle Combustion Turbine Units EU-1 and EU-2	Oxidation Catalyst	60 days / no later than 180 days	HAPs (Formaldehyde)	5 years	HAPs Minor Limit
Auxiliary Boiler	No Control	60 days / no later than 180 days	PM, PM_{10} and $PM_{2.5}$	One time testing	326 IAC 2-2-3
Auxiliary Boiler	No Control	60 days / no later than 180 days	CO	One time testing	326 IAC 2-2-3
Auxiliary Boiler	No Control	60 days / no later than 180 days	VOC	One time testing	326 IAC 2-2-3
Auxiliary Boiler	Low NOx Burner with Flue Gas Recirculation	60 days / no later than 180 days	NOx	5 year	326 IAC 2-2-3
Auxiliary Boiler	No control	60 days / no later than 180 days	Thermal Efficiency	one time testing	326 IAC -2-2-3

Note: Compliance with the NOx emission limits for the combustion turbines are demonstrated by using the NOx CEMs data.

Operations of the high efficiency drift eliminators at all times and a weekly test of the blow-down water quality will ensure compliance with PM/PM_{10}/$PM_{2.5}$ limit for the insignificant cooling towers.

No stack testing are required for the emergency diesel generator and the emergency fire pump engine because these units are emergency units and/or insignificant activities and compliance with the BACT limits are demonstrated through keeping records of the fuel used and purchase of NSPS, Subpart IIII certified engine.
Stack testing of the insignificant dew point heater for PM/PM10/PM2.5, VOC, CO and NOx emission are not justified because of its small size and low emissions rate heater.

(b) The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Range/ Value	Excursions and Exceedances	Limit or Requirement
Oxidation Catalyst	Temperature	Continuous	Value provided by catalyst vendor or as determined from the last compliance stack test	Response steps	326 IAC 2-2-3

(c) The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Value	Excursions and Exceedances	Requirement
EU-1 and EU-2 (SCR with DLN)	NOx CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. T109-26292-00004. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Change 1: The new Combined Cycle Combustion Turbine Generation Facility has been added to Section A.2 - Emission Units and Pollution Control Equipment Summary and Section A.3 - Specifically Regulated Insignificant Activities of the permit.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

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

(a) Two (2) no. 2 fuel oil fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) for control of NO_X emissions, which was voluntarily installed and is not required to operate. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(f) One (1) distillate oil fired generator, identified as Unit PR-10, constructed in 1967, with a design heat input capacity of 28.4 million Btu per hour (MMBtu/hr), exhausting to stack PR10-1.

(g) Coal transfer facilities, with a maximum throughput of 800 tons per hour, with a dust suppression system.

(h) Rail car unloading, coal pile unloading, and coal storage, with a maximum capacity of 800 tons per hour.

(i) Coal crushers, identified as 1A and 1B, with a maximum combined capacity of 800 tons per hour, each using an enclosure for dust control.

(j) One (1) pneumatic fly ash storage silo and handling system, to be constructed in 2009, with a maximum storage capacity of 300 tons and a maximum throughput capacity of 10.0 tons of fly ash per hour. The particulate emissions from the silo loadout to trucks are uncontrolled and exhaust to the atmosphere. The particulate emissions from the silo storage will be controlled by a baghouse, identified as Silo Baghouse, and exhausting to a stack, identified as Silo Stack. The particulate emissions from fly ash conveyance are controlled by a dust collector, identified as Fly Ash Collector, and exhausting to a stack, identified as Vacuum Blower Stack.

Note: The pneumatic fly ash storage silo and handling system was never constructed.

The New Combined Cycle Combustion Turbine Generation Facility Emission Units:

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

***Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners which are a source of emissions.**

(l) **One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.**

(m) **One (1) natural gas fired Dew Point Heater, identified as emission unit EU-4, permitted in 2013, with a rated heat input capacity of 20.8 MMBtu/hr exhausting to stack S-4.**

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

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

(a) Coal bunker and coal scale exhausts. [326 IAC 6-3] [326 IAC 5]

Before the startup of the Combined Cycle Combustion Turbine Generation Facility, the Coal bunker and coal scale exhausts shall be permanently shut down and decommissioned.

(b) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM_{10} 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(1) Wet process ash handling, with hydroveyors conveying ash to storage ponds. [326 IAC 6-4]

Before the startup of the Combined Cycle Combustion Turbine Generation Facility, the Wet process ash handling shall be permanently shut down and decommissioned.

(2) Ponded ash handling/removal operations. [326 IAC 6-4]

(3) Truck traffic on paved road ~~to and from the Silo~~. [326 IAC 6-4]

The New Combined Cycle Combustion Turbine Generation Facility Insignificant Emission Units:

(c) **One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]**

(d) **One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]**

(e) **One (1) evaporative cooling tower, identified as emission unit U-7, rated with a circulation rate of 192,000 gpm to provide non-contact cooling water to the steam turbine condenser, permitted in 2013, and equipped with high efficiency drift eliminators.**

(f) **Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit F-1, permitted in 2013, with fugitive emissions controlled by full enclosure.**

(g) **Fugitive equipment leaks from the natural gas supply lines, identified as F-2 controlled by a Leak Detection and Repair (LDAR) program.**

(h) **Three (3) Turbine Lube Demister Vents, permitted in 2013.**

Change 2: A Condition has been added in Section D.1 that will discontinue the operation of the emission units in Sections D.1, D.2, D.3, D.4, D.5 and the Wet process ash handling in Section D.6 before the startup of the Combined Cycle Combustion Turbine Generation Facility.

SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(a) Two (2) no. 2 fuel oil-fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

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

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

D.1.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.1 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.1.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-2]

(a) Pursuant to 326 IAC 6-2-2(a) (Particulate Emissions Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(b)), the PM emissions from Units 1, 2, 3, 4, 5, and 6 shall not exceed 0.23 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{0.87}{Q^{0.16}}$$

Where Q = total source capacity (MMBtu/hr) on June 8, 1972 = 4,071 MMBtu/hr

(b) Pursuant to 326 IAC 6-2-2(b), the PM emissions from Units 1 and 2 shall not exceed 0.10 pound per million Btu heat input (lb/MMBtu), which is less than 0.23 lb/MMBtu, as requested by the source in a letter dated August 26, 2008.

D.1.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), the following applies to Eagle Valley Units 1 and 2:

(1) When starting a fire in a boiler, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period. [326 IAC 5-1-3(a)]

(2) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the forty percent (40%) opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60) minute period. The averaging periods in excess of the limit set in 326 IAC 5-1-2 shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

(b) If this facility cannot meet the opacity limitations in (a)(1) and (a)(2) of this condition, the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

D.1.3 Sulfur Dioxide (SO_2) [326 IAC 7-4-11]

Pursuant to 326 IAC 7-4-11 (Morgan County Sulfur Dioxide Emission Limitations), the SO_2 emissions from Unit 1 and Unit 2 shall not exceed 0.37 pounds per million Btu (lbs/MMBtu) each. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated using a calendar month average.

Compliance Determination Requirements

D.1.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11] [326 IAC 3-6]

Compliance with the particulate limitations in Condition D.1.1(b) and with the Opacity limits in Section C - Opacity and Temporary Alternative Opacity Limitations for startup shall be determined as follows:

(a) Compliance with the particulate limitations shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. PM testing with both units operating and exhausting to the common stack is permitted. [326 IAC 3-6]

(b) Opacity testing shall be performed in conjunction with the particulate emissions testing in accordance with 40 CFR 60, Appendix A, Method 9. The Method 9 opacity testing (VE readings) shall be recorded for the full duration of the sampling time for each sampling repetition that occurs during daylight hours. [326 IAC 3-5-1(c)(2)(A)(ii)] [326 IAC 5-1-4(a)(1)]

(c) To demonstrate compliance with the Temporary Alternative Opacity Limitation for boiler startups, opacity testing shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, during daylight hours of the startup from light-off to completion of start-up. [326 IAC 3-5-1(c)(2)(A)(ii)] [326 IAC 5-1-4(a)(1)]

(d) The PM stack testing and Method 9 opacity testing shall be repeated as follows:

(1) By December 31 of every second calendar year following this valid compliance demonstration; or

(2) If a unit is not operated at least 1,000 hours in the 2 years since the previous stack test, then testing shall be repeated at least once every 1,000 hours of operation for that unit, or five (5) calendar years from the date of the last valid compliance demonstration, whichever occurs first.

For the purpose of this permit, “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

(e) Testing shall be conducted in accordance with Section C - Performance Testing.

D.1.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 7-2] [326 IAC 7-4-11]

Compliance shall be determined utilizing one of the following options:

(a) Pursuant to 326 IAC 3-7-4, 326 IAC 7-2, and 326 IAC 7-4-11, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed the equivalent of 0.37 pounds per MMBtu each, using a calendar month average, by:

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

(2) Providing analysis of fuel oil samples collected and analyzed in accordance with 326 IAC 3-7-4(a).

(A) Oil samples shall be collected from the tanker truck load during or prior to transferring fuel to the storage tank; or

(B) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank.

(b) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

D.1.6 **RESERVED** ~~Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]~~

~~The Permittee has met the monitoring requirements of 326 IAC 10-4-12(b)(1) through (b)(3) that are applicable to their monitoring systems for the~~ ~~NO_x~~ ~~budget units. The Permittee shall record, report, and quality assure the data from the monitoring systems in accordance with 326 IAC 10-4-12 and 40 CFR 75.~~

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

D.1.7 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the fuel oil-fired boiler exhaust shall be performed once per day during normal daylight operations when one or both of Units 1 and 2 are in operation and burning fuel oil. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(e) If abnormal emissions are observed at any boiler exhaust, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

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

D.1.8 Record Keeping Requirements [326 IAC 2-7-5(3)]

(a) To document compliance with the applicable opacity limits and Conditions D.1.1 and D.1.2, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the opacity and particulate limits established in Section C - Opacity and Conditions D.1.1 and D.1.2.

(1) Data and results from the most recent stack test and accompanying Method 9 visible emissions evaluation results for Units 1 and 2.

(2) Results of the visible emission notations of the stack 1-1 exhaust.

(b) To document compliance with Conditions D.1.3 and D.1.5, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained shall be complete and sufficient to establish compliance with the SO_2 limit as required in Conditions D.1.3 and D.1.5.

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

(2) Monthly weighted average sulfur content.

(3) Fuel heat content.

(4) Fuel consumption.

(5) Monthly weighted average sulfur dioxide emission rate in pounds per million Btus (lb/MMBtu).

(c) To document compliance with Condition D.1.7, the Permittee shall maintain daily records of the visible emission notations of the Boiler stack exhaust. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.1.9 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 7-2(c)]

A quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Condition D.1.3 shall be submitted to the address listed in Section C - General Reporting Requirements of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.2 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB to control NO_X emissions. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) to control NO_X emissions. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

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

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

D.2.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.2 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-2]

(a) Pursuant to 326 IAC 6-2-2 (Particulate Emissions for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(b)), the PM emissions from Units 1, 2, 3, 4, 5, and 6 shall not exceed 0.23 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{0.87}{Q^{0.16}}$$

Where Q = total source capacity (MMBtu/hr) on June 8, 1972 = 4,071 MMBtu/hr

(b) Pursuant to 326 IAC 6-2-2(b), the PM emissions from Units 3, 4, 5 and 6 shall not exceed 0.27 pound per million Btu heat input (lb/MMBtu), as requested by Indianapolis Power and Light Company in a letter dated April 12, 1988.

D.2.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), the following applies:

(1) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed two and one-half (2.5) hours (twenty-five (25) six (6)-minute averaging periods) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit, whichever occurs first. [326 IAC 5-1-3(e)]

(2) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed one (1) hour (ten (10) six (6)-minute averaging periods). [326 IAC 5-1-3(e)]

(3) Operation of the electrostatic precipitator is not required during these times.

(4) During the above startup and shutdown periods all reasonable efforts shall be made to minimize the number and magnitude of the exceedances.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60) minute period. The averaging periods in excess of the limit set in 326 IAC 5-1-2 shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

D.2.3 Sulfur Dioxide (SO_2) [326 IAC 7-4-11]

Pursuant to 326 IAC 7-4-11 (Sulfur Dioxide Emission Limitations for Morgan County):

(a) SO_2 emissions from Unit 3 shall not exceed 0.37 pounds per million Btu (lbs/MMBtu), compliance with which shall be determined as specified in 326 IAC 7-2-1(c), using a thirty (30) day rolling weighted average. [326 IAC 7-4-11(2)]

(b) SO_2 emissions from Units 4, 5, and 6 shall not exceed 3.04 pounds per million Btu (lbs/MMBtu) each, compliance with which shall be determined as specified in 326 IAC 7-2-1(c), using a thirty (30) day rolling weighted average. [326 IAC 7-4-11(2)]

(c) As an exception to the emission limitations specified in (a) and (b), pursuant to 326 IAC 7-4-11(7), at any time in which IPL burns coal on Unit 3, the thirty (30) day rolling weighted average for sulfur dioxide emissions from Units 3, 4, 5, and 6 shall be limited to two and fifty-seven hundredths (2.57) pounds per million Btu each. [326 IAC 7-4-11(3)]

Compliance Determination Requirements

D.2.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to determine compliance with the PM limitation in Condition D.2.1(b) for each units (Units 3, 4, 5 and 6), the Permittee shall conduct before December 31~~, 2009~~ a performance stack test utilizing methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following this valid compliance demonstration. For the purpose of this permit, “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive. Testing shall be conducted in accordance with Section C - Performance Testing.

D.2.5 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitators (ESPs) shall be operated at all times that the boilers vented to the ESPs are in operation. Each flue gas conditioning (FGC) system on Unit 3, Unit 4 and Unit 5 shall be used with the corresponding ESP as necessary to maintain compliance with this permit.

D.2.6 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems for Units 3, 4, 5 and 6 shall be calibrated, maintained, and operated for measuring opacity, SO_2, and either CO_2 or O_2, which meet the performance specifications of 326 IAC 3-5-2.

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

(c) Pursuant to 326 IAC 3-5-4, if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 326 IAC 10-4, or 40 CFR 75.

(e) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

D.2.7 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 7-2] [326 IAC 7-4-11]

(a) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data obtained in accordance with procedures specified under 326 IAC 3-7 may be used to demonstrate compliance as follows:

(1) Pursuant to 326 IAC 7-4-11(6), on a day for which Unit 3 does not burn any coal, compliance with the sulfur dioxide emission limitations in 326 IAC 7-4-11(2) shall be determined as specified in 326 IAC 7-2-1(c), using a thirty (30) day rolling weighted average.

(2) Pursuant to 326 IAC 7-4-11(7), on a day for which Unit 3 burns any coal, if the thirty (30) day rolling weighted average for any unit is above two and fifty-seven hundredths (2.57) pounds per million Btu, then 326 IAC 7-2-1(c)(1) does not apply, and the daily average emission rate for that unit for that day shall not exceed two and fifty-seven hundredths (2.57) pounds per million Btu.

In the alternative, SO_2 emissions may be determined by use of CEM in lieu of any other method prescribed herein.

(b) Pursuant to 326 IAC 7-4-11(8), for the purposes of determining compliance under 326 IAC 7-2-1(b), stack tests performed on Units 3, 4, 5, and 6 shall demonstrate compliance with the most stringent set of limits in effect at any time during the day prior to or during the test based on the Unit 3 operating status and fuel type as indicated by the log maintained pursuant to 326 IAC 7-4-11(9).

D.2.8 **RESERVED** ~~Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]~~

~~The Permittee has met the monitoring requirements of 326 IAC 10-4-12(b)(1) through (b)(3) that are applicable to their monitoring systems for the~~ $\cancel{NO_x}$ ~~budget units. The Permittee shall record, report, and quality assure the data from the monitoring systems in accordance with 326 IAC 10-4-12 and 40 CFR 75.~~

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

D.2.9 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) The ability of the ESP to control particulate emissions shall be monitored once per day, when the unit is in operation, by measuring and recording the number of T-R sets in service and the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets.

(b) Reasonable response steps shall be taken in accordance with Section C – Response to Exceedances or Excursions whenever the percentage of T-R sets in service falls below 90 percent (90%). T-R set failure resulting in less than 90 percent (90%) availability is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Exceedances or Excursions shall be considered a deviation from this permit.

D.2.10 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) In the event of emissions exceeding thirty percent (30)%) average opacity for three (3) consecutive six (6) minute averaging periods, appropriate response steps shall be taken in accordance with Section C - Response to Exceedances or Excursions such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below thirty percent (30%). Examples of expected response steps include, but are not limited to, boiler loads being reduced, adjustment of flue gas conditioning rate, and ESP T-R sets being returned to service.

(b) Opacity readings in excess of thirty percent (30%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Exceedances or Excursions, shall be considered a deviation from this permit.

D.2.11 SO_2 Monitor Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

(a) Whenever the SO_2 continuous emission monitoring (CEM) system is malfunctioning or down for repairs or adjustments and a backup CEM is not brought on-line, the following shall be used to provide information related to SO_2 emissions:

(1) If the CEM system is down for less than twenty-four (24) hours and a backup CEM is not brought on-line, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(2) If the CEM system is down for twenty-four (24) hours or more and a backup CEM is not brought on-line, the Permittee shall either:

(A) Conduct fuel sampling as specified in 326 IAC 3-7-2(b). Fuel sample preparation and analysis shall be conducted as specified in 326 IAC 3-7-2(c), 326 IAC 3-7-2(d), and 326 IAC 3-7-2(e). Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring: or

(B) Comply with the relevant requirements of 40 CFR Part 75. Subpart D - Missing Data Substitution Procedures

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

D.2.12 Record Keeping Requirements

(a) To document compliance with the applicable opacity and particulate limits and Conditions D.2.1 and D.2.2, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the opacity and particulate limits in Section C - Opacity and in Conditions D.2.1 and D.2.2.

(1) Data and results from the most recent stack test.

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5.

(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime.

(4) All ESP parametric monitoring readings.

(b) To document compliance with SO_2 Condition D.2.3, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the SO_2 limits as required in Condition D.2.3. The Permittee shall maintain records in accordance with (2) and (3) or (4) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6 and 326 IAC 7-2-1(g).

(2) All fuel sampling and analysis data collected for SO_2 CEM downtime, in accordance with Condition D.2.11.

(3) Calculated actual fuel usage during each SO_2 CEM downtime for the Unit(s) affected by CEM downtime lasting 24 or more hours.

(4) The substitute data used for the missing data periods if data substitution pursuant to 40 CFR Part 75 Subpart D is used to provide data for the SO_2 CEM downtime, in accordance with Condition D.2.11.

(c) Pursuant to 326 IAC 7-4-11(9), the Permittee shall maintain and make available to the department upon request a log of the operating status and fuel type used for Unit 3. In addition, in the quarterly report required by 326 IAC 7-2-1(a), the Permittee shall submit to the department a daily summary indicating fuel type for Unit 3, and, for days on which Unit 3 burned any coal and any thirty (30) day rolling weighted average was greater than two and fifty-seven hundredths (2.57) pounds per million Btu, the Permittee shall submit to the department the daily average sulfur content, heat content, and sulfur dioxide emission rate for Units 3, 4, 5, and 6. For the purposes of this Condition, "department" refers to the Indiana Department of Environmental Management (IDEM).

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.2.13 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 3-5-7] [326 IAC 7-2(c)]

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Condition D.2.3 shall be submitted to the address listed in Section C - General Reporting Requirements of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

(1) Date of downtime.

(2) Time of commencement.

(3) Duration of each downtime.

(4) Reasons for each downtime.

(5) Nature of system repairs and adjustments.

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

SECTION D.3 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(f) One (1) distillate oil fired generator, identified as Unit PR-10, constructed in 1967, with a design heat input capacity of 28.4 million Btu per hour (MMBtu/hr), exhausting to stack PR10-1.

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

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

D.3.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.3 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown

D.3.1 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO_2 emissions from Unit PR-10 shall not exceed 0.5 pound per million Btu (lb/MMBtu).

Compliance Determination Requirements

D.3.2 Sulfur Dioxide Emissions and Sulfur Content] [326 IAC 7-1.1-2] [326 IAC 7-2]

Pursuant to 326 IAC 3-7-4, 326 IAC 7-1.1-2, and 326 IAC 7-2, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed the equivalent of 0.5 lb/MMBtu, using a calendar month average, by:

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

(b) Providing analysis of fuel oil samples collected and analyzed in accordance with 326 IAC 3-7-4(a).

(1) Oil samples shall be collected from the tanker truck load during or prior to transferring fuel to the storage tank; or

(2) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank.

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

D.3.3 Record Keeping Requirements

(a) To document compliance with Condition D.3.1 and D.3.2, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained shall be complete and sufficient to establish compliance with the SO_2 limit as required in Condition D.3.1 and D.3.2.

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

(2) Monthly weighted average sulfur content.

(3) Fuel heat content.

(4) Fuel consumption.

(5) Monthly weighted average sulfur dioxide emission rate in pounds per million Btus (lb/MMBtu).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.3.4 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 7-2(c)]

A quarterly summary of the information to document compliance with Condition D.3.1 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

SECTION D.4 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(g) Coal transfer facilities, with a maximum throughput of 800 tons per hour, with a dust suppression system.

(h) Rail car unloading, coal pile unloading, and coal storage, with a maximum capacity of 800 tons per hour.

(i) Coal crushers, identified as 1A and 1B, with a maximum combined capacity of 800 tons per hour, each using an enclosure for dust control.

Insignificant Activities:
Coal bunker and coal scale exhausts.

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

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

D.4.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.4 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.4.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the coal processing drop points and the particulate emission rate from the coal crushers shall not exceed amounts determined by the following:

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

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

(b) Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0 P^{0.11} - 40$ where E = rate of emission in pounds per hour; and P = process weight rate in tons per hour.

When the process weight rate exceeds two hundred (200) tons per hour, the allowable emission may exceed the pounds per hour limitation calculated using the above equation, provided the concentration of particulate in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

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

D.4.2 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of any coal transfer exhaust points shall be performed once per week during normal daylight operations when transferring coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the rail car unloading shall be performed once per week during normal daylight operations when unloading coal. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the coal crusher stack exhaust shall be performed once per week during normal daylight operations when the crusher is in operation. A trained employee shall record whether emissions are normal or abnormal.

(d) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(e) 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.

(f) 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.

(g) If abnormal emissions are observed at a transfer point exhaust or crusher exhaust or from the coal unloading, 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.

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

D.4.3 Record Keeping Requirements

(a) To document compliance with Condition D.4.2, the Permittee shall maintain weekly records of the visible emission notations of the rail car unloading, crusher and coal transfer exhaust. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]:

(j) One (1) pneumatic Fly Ash Conveyance and Silo Storage (fly ash storage silo and handling system), to be constructed in 2009, with a maximum storage capacity of 300 tons and a maximum throughput capacity of 10.0 tons of fly ash per hour. The particulate emissions from the silo loadout to trucks are uncontrolled and exhaust to the atmosphere. The particulate emissions from the silo storage will be controlled by a baghouse, identified as Silo Baghouse, and exhausting to a stack, identified as Silo Stack. The particulate emissions from fly ash conveyance are controlled by a dust collector, identified as Fly Ash Collector, and exhausting to a stack, identified as Vacuum Blower Stack.

Note: The pneumatic fly ash storage silo and handling system was never constructed.

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

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

D.5.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the emission units in Section D.5 before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.5.1 PSD Minor Limits and Nonattainment NSR [326 IAC 2-2] [326 IAC 2-1.1-5]

The Permittee shall comply with the following:

(a) The combined PM emissions from the Fly Ash Conveyance and Silo Storage shall not exceed 3.9 pounds per hour.

(b) The combined PM_{10} emissions from the Fly Ash Conveyance and Silo Storage shall not exceed 2.9 pounds per hour.

Compliance with these limits in combination with other emission units will limit the PM and PM10 emissions from the Fly Ash Conveyance and Silo Storage (fly ash storage and handling system) to less than 25 and 15 tons per year, respectively and render the requirements of 326 IAC 2-2 (PSD) and 326 IAC 2-1.1-5 (Nonattainment NSR) not applicable to the Fly Ash Conveyance and Silo Storage (fly ash storage and handling system) permitted in 2008.

D.5.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the Fly Ash Conveyance and Silo Storage (fly ash storage and handling system) shall not exceed 19.2 pounds per hour, each, when operating at a process weight rate of 10 tons per hour, each. The pound per hour limitation was calculated with the following equation:

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

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

Compliance Determination Requirements

D.5.3 Particulate Matter (PM)

(a) In order to comply with Conditions D.5.1 and D.5.2, the baghouse and fly ash collector shall be in operation at all times when the fly ash storage and handling is in operation.

(b) 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.5.4 Testing Requirements [326 IAC 2-7-6(1)][326 IAC 2-1.1-11]

Within 180 days after initial startup of the fly ash handling and storage system, in order to demonstrate compliance with Conditions D.5.1 and D.5.2, the Permittee shall perform PM/PM10 testing on baghouse and the dust collector controlling the fly ash storage and handling system utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with Section C - Performance Testing.

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

D.5.5 Visible Emissions Notations

(a) Visible emission notations of the fly ash storage and handling stack exhausts shall be performed once per week 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.5.6 Parametric Monitoring

The Permittee shall record the pressure drop across the fly ash storage and handling baghouse and dust collector used in conjunction with the fly ash storage and handling at least once per day when the fly ash storage and handling is in operation. When for any one reading, the pressure drop across the baghouse or the fly ash collector is outside the normal range of 1.0 and 10.0 inches of water, or a range established during the latest stack test 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.

The instrument used for determining the pressure shall comply with condition C.14 - Instrument Specifications, be subject to approval by IDEM, OAQ, and shall be calibrated at least once every six (6) months.

D.5.7 Broken or Failed Bag Detection

(a) For a single compartment baghouse controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has been repaired or replaced.

(b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit has been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in the emissions unit.

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, or dust traces.

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

D.5.8 Record Keeping Requirements

(a) To document compliance with Condition D.5.5 - Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the fly ash storage and handling stack exhaust. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(b) To document compliance with Condition D.5.6 - Parametric Monitoring, the Permittee shall maintain the daily records of the pressure drop across the baghouse and fly ash collector controlling the fly ash storage and handling. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

(c) All records shall be maintained in accordance with Section C - General Record Keeping Requirements of this permit.

SECTION D.6 FACILITY CONDITIONS

Facility Description [326 IAC 2-7-5(15)] Insignificant Activities:

(1) Wet process ash handling, with hydroveyors conveying ash to storage ponds.

(2) Ponded ash handling/removal operations.

(3) Truck traffic on paved road ~~to and from the Silo~~.

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

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

D.6.0 Air Quality Analysis Requirements [326 IAC 2-2-4]

Pursuant to the air quality impact assessment requirements of 326 IAC 2-2-4, the Permittee shall permanently discontinue the operation of the "wet process ash handling with hydroveyors conveying ash to storage ponds" before commercial operation of the Combined Cycle Combustion Turbine Generation Facility. The requirements of this section will no longer be applicable after the units are permanently shutdown.

D.6.1 Fugitive Dust Emission Limitations [326 IAC 6-4-2]

Pursuant to 326 IAC 6-4-2:

(a) Any ash storage pond area generating fugitive dust shall be in deviation from this rule (326 IAC 6-4) if any of the following criteria are violated:

(1) A source or combination of sources which cause to exist fugitive dust concentrations greater than sixty-seven percent (67%) in excess of ambient upwind concentrations as determined by the following formula:

$$P = \frac{100 (R) - U)}{U}$$

Where
P = Percentage increase
R = Number of particles of fugitive dust measured at downward receptor site
U = Number of particles of fugitive dust measured at upwind or background site

(2) The fugitive dust is comprised of fifty percent (50%) or more respirable dust, then the percent increase of dust concentration in subdivision (1) of this section shall be modified as follows:

$P_R = (1.5 \pm N) P$

Where
N = Fraction of fugitive dust that is respirable dust;
P_R = allowable percentage increase in dust concentration above background; and
P = no value greater than sixty-seven percent (67%).

(3) The ground level ambient air concentrations exceed fifty (50) micrograms per cubic meter above background concentrations for a sixty (60) minute period.

(4) If fugitive dust is visible crossing the boundary or property line of a source. This subdivision may be refuted by factual data expressed in subdivisions (1), (2) or (3) of this section. 326 IAC 6-4-2(4) is not federally enforceable.

(b) Pursuant to 326 IAC 6-4-6(6) (Exceptions), fugitive dust from a source caused by adverse meteorological conditions will be considered an exception to this rule (326 IAC 6-4) and therefore not in violation.

Adverse weather conditions do not relieve a source from taking all reasonable measures to mitigate fugitive dust formation and transport. Failure to take reasonable measures during this period may be considered to be a deviation from this permit.

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

D.6.2 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the fly ash storage pond area(s) shall be performed at least once per week 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.

(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 visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, 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.

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

D.6.3 Record Keeping Requirements

(a) To document compliance with Condition D.6.2, the Permittee shall maintain weekly records of the visible emission notations of the fly ash storage pond area(s). The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

Change 3: The new emission units and there conditions have been added to Section D.7, D.8, D.9, D.10, D.11, D.12, D.13 and D.14 of the permit.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

***Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners which are a source of emissions.**

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

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

D.7.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 16.8 pounds per hour, each and 0.0066 pounds per MMBtu, each with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 13.9 pounds per hour, each and 0.0055 pounds per MMBtu, each without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(c) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.2 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The H_2SO_4 emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall be limited by restricting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

(b) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.3 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The CO emissions from the CCCTs shall be controlled by a catalytic oxidation; and

(b) The CO emissions shall not exceed 2.0 ppmvd @15% O2 based on a 3-hour average.

(c) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.4 VOC PSD BACT [326 IAC 2-2-3][326 IAC 8-1-6]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)) and 326 IAC 8-1-6, the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The VOC emissions from the CCCTs shall be controlled by a catalytic oxidation;

(b) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hour average.

(c) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hour average.

(d) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.5 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The NOx emissions from the CCCTs shall be controlled by a Selective Catalytic Reduction and Dry Low NOx combustors.

(b) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hour average.

(c) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

D.7.6 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2 shall be as follows:

(a) The net heat rate shall not exceed 7,750 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(b) The total CO_2e emissions for both combined cycle combustion turbines shall be limited to less than 2,649,570 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

D.7.7 Hazardous Air Pollutants (HAPs) Minor Limits

The emissions of single HAP, formaldehyde, from the combined cycle combustion turbines identified as EU-1 and EU-2, shall be limited to less than nine (9.0) tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with the above limits, combined with the potential to emit formaldehyde emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of formaldehyde and make the source an area source of HAPs.

D.7.8 Startup and Shutdown Limitations for Combustion Turbines [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the following shall apply to each combustion turbine:

(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves consecutive CEMS data points in compliance with the primary BACT limits.

(b) Steady-state operating condition shall be defined as the period of time that the combustion turbine is operating in dry low NOx (premix) mode and in compliance with the primary BACT limit.

(c) A shutdown is defined as operation beginning when the combustion turbine exits dry low-NOx (premix) mode and ending with termination of continuous fuel flow to each turbine.

(d) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(e) Unit Offline is represented by the Unit on-line Time being 0.

(f) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown

For CO and NO_X, the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCTs. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor. Therefore, the source proposes to use the cold start emission totals, per CCCT as a short-term limit during startup/shutdown events, as follows:

CO - 3,390 lb/event

NOx - 429 lb/event

(g) The total NO_X emissions from the combined cycle combustion turbines stacks shall not exceed 68 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(h) The total CO emissions from the combined cycle combustion turbines stacks shall not exceed 565 tons per twelve (12) consecutive month period, for the duration of

the combined startup and shutdown events, with compliance determined at the end of each month.

(i) The total VOC emissions from the combined cycle combustion turbines stacks shall not exceed 146 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

Compliance Determination Requirements

D.7.9 Oxidation Catalyst

In order to ensure compliance with Conditions D.7.3, D.7.4 and D.7.7, the oxidation catalyst shall be in operation at all times when the natural gas-fired combined cycle combustion turbines are in operation except during periods of startup and shutdown.

D.7.10 Nitrogen Oxide Control

In order to ensure compliance with Condition D.7.5 - NOx PSD BACT, the Selective Catalytic Reduction and Dry Low NOx combustors shall be in operation and control emissions from the natural gas-fired combustion turbines at all times that the natural gas-fired combined cycle combustion turbines are in operation except during periods of startup and shutdown.

D.7.11 H_2SO_4 Compliance Determination Requirements [326 IAC 2-2]

In order to ensure compliance with Condition D.7.2, the Permittee shall maintain a record of the monthly average sulfur content of the natural gas based on vendor data.

D.7.12 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.7.6 - GHGs PSD BACT, the following equation shall be used to determine the CO_2e emissions from the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2:

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

Where:

Fuel Usage (mmscf/month) = monthly fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas or vendor data, if available
CO_2 EF (lb/mmbtu) = 120 lbs/mmbtu for combustion with duct firing and 122 lbs/mmbtu for combustion without duct firing
CH_4 EF (lb/mmbtu) = 0.0022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = 0.00022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

D.7.13 HAPs Minor Limits Calculations

To determine the compliance status with Condition D.7.7 - Hazardous Air Pollutants (HAPs) minor Limits, the following equation shall be used to determine formaldehyde emissions from the natural gas-fired combined cycle combustion turbines, identified as EU-1 and EU-2:

L (tons/month)= (7.1×10^{-4} x Qu + C x Qc)/2000 lbs/ton

Where:

L = 9 tons of (formaldehyde) per 12 month rolling period.

7.1×10^{-4} is the uncontrolled emission factor for formaldehyde (lbs/MMBtu)

Qu = 12- month rolling total heat input to the CT units (MMBtu) when the oxidation catalyst is not fully operational during startup and shutdown conditions

Qc = 12- month rolling total heat input to the CT units (MMBtu) when the oxidation catalyst is fully operational (includes heat input to duct burners).

C = is the controlled emission factor for formaldehyde (lbs/MMBtu), which would be based on stack test results of the CCCTs. Prior to stack testing the factor will be conservatively assumed to equal 60% of the uncontrolled emission factor.

D.7.14 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5][326 IAC-2-2-3]

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

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

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

(d) Whenever a NOx or O_2 CEMS is down for more than twenty-four (24) hours, the Permittee shall monitor the catalyst inlet temperature used in conjunction with the CCCT units with a continuous temperature monitoring system and comply with the following:

The Permittee shall measure the operating temperature of the catalyst inlet bed temperature no less often than once per four (4) hours. In the event of a monitoring system malfunction, failure to measure the operating temperature of the catalyst bed inlet temperature is not a deviation of the permit. Failure to take response steps shall be considered a deviation from the permit. If the measured temperature is below the minimum temperature as supplied by the manufacturer, reasonable response steps shall be taken to return the catalyst bed inlet temperature to the required minimum temperature. A reading that is below the minimum temperature is not a deviation from this permit. Failure to take response steps in accordance with Section C – Response to Excursions or Exceedances shall be considered a deviation from this permit.

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

D.7.15 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Conditions D.7.1 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one

hundred and eighty (180) days after initial startup, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with and without the duct burners in operation. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.7.3 - CO PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct CO emissions stack testing of the emissions from the oxidation catalyst controlling the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with the duct burners in operation. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.7.4 - VOC PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from oxidation catalyst controlling the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with and without the duct burners in operation. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) In order to demonstrate compliance with Condition D.7.6(a) - GHGs PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct net heat rate performance testing for combined cycle combustion turbines utilizing methods as approved by the commissioner. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) In order to demonstrate compliance with Condition D.7.7 - Hazardous Air Pollutants (HAPs) minor Limits, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct HAPs (formaldehyde) emissions stack testing of the emissions from oxidation catalyst controlling the combined cycle combustion turbines utilizing methods as approved by the commissioner. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

D.7.16 Oxidation Catalyst Parametric Monitoring [40 CFR 64]

(a) In order to ensure compliance with Conditions D.7.3, D.7.4 and D.7.7, a continuous monitoring system shall be calibrated, maintained, and operated on the oxidation catalyst for measuring operating temperature. For the purposes of this condition, continuous monitoring means recording the temperature no less often than every 15 minutes. The output of this system shall be recorded as a three (3) hour average. From the date of the start up of the oxidation catalyst until the approved stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 3-hour average temperature of 500°F.

(b) On and after the date the approved stack test results are available, the Permittee shall operate the oxidation catalyst at or above the three (3) hour average temperature specified by the catalyst manufacturer for VOC, CO and formaldehyde control or as established during the most recent compliant stack test.

(c) Section C - Response to Excursions or Exceedences contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature average below the three hour average specified by the catalyst manufacturer for VOC, CO and formaldehyde control or as established in the most recent compliance stack test is not considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

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

D.7.17 Record Keeping Requirement

(a) In order to document the compliance status with Conditions D.7.1, D.7.2, D.7.3, D.7.4, D.7.5, D.7.6 and D.7.7, the Permittee shall maintain monthly records of the amount and type of fuel combusted in the combined cycle combustion turbines.

(b) To document the compliance status with Condition D.7.2 - H_2SO_4 PSD BACT, the Permittee shall maintain the monthly records of the fuel sulfur content of the natural gas combusted in the turbines and the associated duct burners.

(c) To document the compliance status with Condition D.7.6 (b) - GHGs PSD BACT, the Permittee shall maintain monthly records of the CO_{2e} emissions.

(d) To document the compliance status with the emission limits in Condition D.7.7 - Hazardous Air Pollutants (HAPs) minor Limits, the Permittee shall maintain monthly records of the formaldehyde emissions.

(e) To document compliance with Condition D.7.8 - Startup and Shutdown Limitations for Combustion Turbines, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup, shutdown) with supporting operational data;

(2) The total number of minutes for startup and shutdown operation per event; and

(3) Records shall be maintained at any time the unit is off-line.

(4) The CEMS data, fuel flow meter data, and/or Method 19 calculations used to determine the mass emissions rate corresponding to each startup and shutdown operating period.

(f) To document the compliance status with Condition D.7.14 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall record the output of the continuous monitoring systems and shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(g) In the event that a breakdown of the NOx or O_2 continuous emission monitoring system (CEMS) occurs in Condition D.7.14 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(h) To document the compliance status with Conditions D.7.14 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain the monthly records of the NOx emissions from each of the combined cycle combustion turbines EU-1 and EU-2 based upon the CEM data.

(i) In order to document the compliance status with Condition D.7.16 - Oxidation Catalyst Parametric Monitoring, the Permittee shall maintain continuous temperature records (on a three- (3-) hour average basis) for each oxidation catalyst to demonstrate compliance.

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

D.7.18 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.7.6(b), D.7.7, D.7.8(h), D.7.8(i) and D.7.8(j) shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(l) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

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

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

D.8.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The PM, $PM_{2.5}$ and PM_{10} emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.005 lb/MMBtu and 0.4 lbs/hour, based on a 3-hr average period through the use of good combustion practices and fuel specification.

D.8.2 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

(a) The H_2SO_4 emissions from the auxiliary boiler, identified as EU-3 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

D.8.3 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The CO emissions from the Auxiliary Boiler (EU-3) operation shall not exceed 0.083 lb/MMBtu and 6.5 lbs/hr, based on a 3 - hour average through the use of advanced ultra - low NOx burner.

D.8.4 VOC PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The VOC emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.42 lbs/hr, based on a 3-hr average period through the use of advanced ultra - low NOx burner.

D.8.5 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

(a) The NOx emissions from the Auxiliary Boiler, identified as EU-3 shall be controlled by Low NOx Burners with Flue Gas Recirculation.

(b) The NOx emissions shall be limited to less than 0.011 lb/MMBtu and 0.87 pounds per hour, based on a 3-hour average period.

D.8.6 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as EU-3 shall be as follows:

The GHGs BACT for the Auxiliary Boiler shall be as follows:

(a) Operating and Maintenance (O&M) Practices;

(b) Combustion Turning;

(c) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(d) The boiler will be equipped with an economizer;

(e) The boiler will be equipped with a condensate return system (recovery);

(f) Steam and hot lines will be insulated; and

(g) Boiler designed for 80% thermal efficiency (HHV).

(h) The total CO_2e emissions for Auxiliary Boiler shall be limited to less than 40,639 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

D.8.7 Startup, Shutdown and Other Opacity Limits [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (a) (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the applicable opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable opacity limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period.

(b) If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(a) or (b), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

Compliance Determination Requirements

D.8.8 Nitrogen Oxide Control

In order to ensure compliance with Condition D.8.5 - NOx PSD BACT, the Low NOx Burners with Flue Gas Recirculation shall be installed and utilized at all times that the auxiliary boiler is in operation.

D.8.9 H_2SO4 Compliance Determination Requirements [326 IAC 2-2]

In order to ensure compliance with Condition D.8.2, the Permittee shall maintain a record of the monthly average sulfur content of the natural gas based on vendor data.

D.8.10 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.8.1 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.8.3 - CO PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct CO emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.8.4 - VOC PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) In order to demonstrate compliance with Condition D.8.5 - NOx PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct NOx emissions stack testing of the emissions from the auxiliary boiler utilizing methods as approved by the commissioner. This test shall be repeated by December 31 of every fifth year following the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) In order to demonstrate compliance with Condition D.8.6(h) – GHGs PSD BACT, within sixty (60) days of reaching maximum capacity but no later than 180 days after initial startup, the Permittee shall perform thermal efficiency testing of the auxiliary boiler, identified as EU-3 utilizing methods approved by the Commissioner. These tests shall be conducted once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.8.11 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.8.6(h), the following equation shall be used to determine the CO_2e emissions from the Auxiliary Boiler:

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

GWP)] x 1/2000 (ton/lb)

Where:
Fuel Usage (mmscf/month) = monthly auxiliary boiler fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas, or vendor data, if available
CO_2 EF (lb/mmbtu) = 117 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = 0.0022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = 0.00022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.8.12 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.8.1, D.8.2, D.8.3, D.8.4, D.8.5, D.8.6 and D.8.11, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the auxiliary boiler.

(b) To document the compliance status with Condition D.8.2 - H_2SO_4 PSD BACT, the Permittee shall maintain the monthly vendor records of the fuel sulfur content of the natural gas combusted in the auxiliary boiler.

(c) To document the compliance status with Condition D.8.6(h) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_{2e} emissions from the auxiliary boiler.

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

D.8.13 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.8.6(h) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(m) One (1) natural gas fired Dew Point Heater, identified as emission unit EU-4, permitted in 2013, with a rated heat input capacity of 20.8 MMBtu/hr exhausting to stack S-4.

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

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

D.9.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Dew Point Heater, identified as EU-4 shall be limited to less than 0.0072 lb/MMBtu and 0.15 lbs/hr, based on a 3-hr average period through the use of good combustion practices and fuel specification.

D.9.2 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

(a) The H_2SO_4 emissions from the dew point heater, identified as EU-4 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

D.9.3 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

The CO emissions from the Dew Point Heater (EU-4) operation shall not exceed 0.082 lb/MMBtu and 1.7 lbs/hr, based on a 3 - hour average through the use of good combustion and low NOx burners.

D.9.4 VOC PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

The VOC emissions from the Dew Point Heater, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.11 lbs/hr, based on a 3-hr average period through the use of good combustion and low NOx burners.

D.9.5 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

(a) The NOx emissions from the Dew Point Heater, identified as EU-4 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(b) The NOx emissions shall be limited to less than 0.032 lb/MMBtu and 0.67 pounds per hour, based on a 3-hr average period.

D.9.6 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater, identified as EU-4 shall be as follows:

(a) The good engineering design and Combustion Practices.

(b) The use of only natural gas.

(c) The total CO_2e emissions for Dew Point Heater shall be limited to less than 10,659 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance Determination Requirements

D.9.7 Nitrogen Oxide Control

In order to ensure compliance with Condition D.9.5 - NOx PSD BACT, the low NOx burner shall be installed and utilized at all times that the dew point heater, identified as EU-4 is in operation.

D.9.8 Compliance Determination Requirements [326 IAC 2-2]

In order to determine compliance status with Conditions D.9.1 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.9.2 - H_2SO_4 PSD BACT, the Permittee shall only use natural gas in the dew point heater EU-4.

D.9.9 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.9.6(c), the following equation shall be used to determine the CO_2e emissions from the dew point heater, identified as EU-4:

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

Where:
Fuel Usage (mmscf/month) = monthly dew point heater usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas, or vendor data, if available
CO_2 EF (lb/mmbtu) = 117 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = 0.0022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = 0.00022 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.9.10 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.9.1, D.9.2, D.9.3,

D.9.4, D.9.5, and D.9.6, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the auxiliary boilers.

(b) To document the compliance status with Condition D.9.6(c) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_{2e} emissions from the auxiliary boilers.

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

D.9.11 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.9.6(c) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(c) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(d) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

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

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

D.10.1 PM, PM_{10}, $PM_{2.5}$, NOx, CO, H_2SO_4 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Emergency Generator, identified as emission unit EU-5 shall be as follows:

Emergency Diesel Generator, identified as (EU5):

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Generator, Identified as EU-5, shall not exceed 0.15 g/hp-hr, through the use of combustion design control.

(b) The H_2SO4 emissions;

1. **The sulfur content of the fuel oil shall not exceed 15ppm.**

(c) The CO emissions from the Emergency Generators, Identified as EU-5 shall not exceed 2.6 g/hp-hr through the use of combustion design controls and usage limitation.

(d) The NOx and VOC emissions from the Emergency Generator shall be limited to less than 4.8 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

(e) The GHGs BACT for the Emergency Diesel Generator, Identified as EU5 shall be as follows:

1. **The use of a good engineering design; and**
2. **The total CO_2e emissions for Emergency Diesel Generator shall be limited to less than 605 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.**

D.10.2 PM, PM_{10}, $PM_{2.5}$, NOx, CO, H_2SO_4 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Emergency Fire Pump, identified as emission unit EU-6 shall be as follows:

Emergency Fire Pump Engine, identified as EU-6:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Fire Pump Engine shall not exceed 0.15 g/hp-hr through the use of combustion design control.

(b) H_2SO_4 BACT Limits

1. The sulfur content of the fuel oil shall not exceed 15ppm.

(c) The CO emissions from the Emergency Fire pump Engine shall not exceed 2.6 g/hp-hr through the use of combustion design controls and usage limitation.

(d) The NOx and VOC emissions from the Emergency Fire Pump Engine shall not exceed 3.0 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls and usage limitation.

(e) The GHGs BACT for the Emergency Diesel Generator, Identified as EU-6 shall be as follows:

1. The use of a good engineering design; and

2. The total CO_2e emissions for Firewater Pump Engine shall be limited to less than 157.50 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance Determination Requirements

D.10.3 Greenhouse Gases (GHGs) Calculations

(a) To determine the compliance status with Condition D.10.1(e)(2), the following equation shall be used to determine the CO_2e emissions from the Emergency Diesel Generator (EU-5):

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

Where:

Fuel Usage (gal/month) = monthly emergency generator fuel usage data from company records
Heat Content (mmbtu/gal) = standard value in AP-42 for diesel fuel, or vendor data, if available
CO_2 EF (lb/mmbtu) = 163 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CH_4 EF (lb/mmbtu) = 0.00661 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
N_2O EF (lb/mmbtu) = 0.00132 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

(b) To determine the compliance status with Condition D.10.2(g)(3), the following equation shall be used to determine the CO_{2e} emissions from the Emergency Fire Pump Engine (EU-6):

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

Where:

Fuel Usage (gal/month) = monthly fire pump engine fuel usage data from company records
Heat Content (mmbtu/gal) = standard value in AP-42 for diesel fuel, or vendor data, if available
CO_2 EF (lb/mmbtu) = 163 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CH_4 EF (lb/mmbtu) = 0.00661 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
N_2O EF (lb/mmbtu) = 0.00132 lbs/MMBtu emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CO_2 GWP = 1.0 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.10.4 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.10.1(c) and D10.2(c), the Permittee shall maintain monthly records of the percent sulfur content of the fuel used in the emergency diesel engine and the fire pump engine.

(b) To document compliance with Conditions D.10.1(h) and D.10.2(h), the Permittee shall maintain monthly records of hours of operation of the emergency diesel engine and the fire pump engine.

(c) To document the compliance status with Conditions D.10.1(g)(3), D.10.2(g)(3) and D.10.3, the Permittee shall maintain records of the total amount of fuel used each month in the emergency diesel engine and fire pump engine and the total CO_{2e} emissions from the emergency diesel engine and fire pump engine.

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

D.10.5 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.10.1(e)(2) and D.10.2(e)(2) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities
(e) One (1) evaporative cooling tower, identified as emission unit U-7, rated with a circulation rate of 192,000 gpm to provide non-contact cooling water to the steam turbine condenser, permitted in 2013, and equipped with high efficiency drift eliminators.
(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

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

D.11.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the cooling water, identified as EU-7 shall be as follows:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Tower, identified as U-7 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and maximum total dissolved solids (TDS) shall be less than 5000 ppm.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Tower shall be less than 2.4, 1.5 and 0.005 pounds per hour, respectively.

Compliance Determination

D.11.2 PM, PM_{10} and $PM_{2.5}$ Control

(a) In order to ensure compliance with Conditions D.11.1 - PM and PM_{10} and $PM_{2.5}$ PSD BACT, the high efficiency drift eliminators for particulate control shall be in operation and control emissions from each cooling tower at all times that the cooling towers are in operation.

(b) The Permittee shall perform monthly tests of the blow-down water quality using EPA-approved method. This monthly test shall not be required for any 30-day period in which the wet cooling tower is not in operation, provided that the Permittee maintains a log of wet cooling tower operation.

(c) The Permittee shall calculate the PM, PM_{10}, and $PM_{2.5}$ emission rates using an equation based on the TDS and water circulation rate using the following formula.

$$E = (c \times T \times Q \times 8.34 \times 60 \times DR) / 10^6$$

Where:

E = mass emission rate in lbs/hr for PM, PM_{10} and $PM_{2.5}$;
c = particle size fraction (c=1 for PM; 0.635 for PM_{10} and 0.00213 for $PM_{2.5}$);
T = Total Dissolved Solids, mg/l;
Q = Cooling tower circulation rate, gallons/min; and
DR = Drift rate (assumed to be 0.0005% based on design).

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

D.11.3 Record Keeping Requirements

(a) To document the compliance status with Condition D.11.1, the Permittee shall maintain a log that contains the date and result of each blow-down water quality test and resulting mass rate. This log shall be maintained onsite for a minimum of five years and shall be provided to EPA and IDEM upon request.

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

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(f) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit F-1, permitted in 2013, with fugitive emissions controlled by full enclosure.

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

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

D.12.1 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Electrical Circuit Breakers, identified as SF6 shall be as follows:

(1) The use of totally enclosed pressure system with a design leak rate of 0.5% by weight and a density alarm for leak detection.

(2) The total SF_6 emissions from all the circuit breakers shall not exceed 59.8 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities **(g) Fugitive equipment leaks from the natural gas supply lines, identified as F-2 controlled by a Leak Detection and Repair (LDAR) program.** **(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)**

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

D.13.4 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Fugitive equipment leaks shall be as follows:

The BACT for fugitive GHG emissions shall be use of Auditory, Visual, and Olfactory (AVO) Monitoring program for methane leaks.

SECTION D.14 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(h) Three (3) Turbine Lube Demister Vents, permitted in 2013.

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

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

D.14.1 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Significant Source Modification 109-32471-00004 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Turbine Lube Oil Demister Vents shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents shall be the use of good design and operating practices.

Change 4: The new emission units and there conditions have been added to Section E.1, E.2, E.3, E.4 and Section G of the permit.

SECTION E TITLE IV CONDITIONS

Oris Code: 991

Title IV Source Description:

(a) Two (2) no. 2 fuel oil fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) for control of NO_X emissions, which was voluntarily installed and is not required to operate. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

<u>The New Combined Cycle Combustion Turbine Generation Facility Emission Units:</u>

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

***Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.**

(The information contained in this box is descriptive information and does not constitute enforceable conditions.)

Acid Rain Program

E.1.**1** Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21] [40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78. The Acid Rain permit for this source is attached to this permit as Attachment A, and is incorporated by reference.

E.**1.**2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

***Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.**

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

New Source Performance Standards (NSPS) Requirements [326 IAC 12][40 CFR 60, Subpart KKKK]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the two (2) natural gas combustion turbines EU-1 and EU-2 and two (2) duct burners associated with the heat recovery steam generators, except as otherwise specified in 40 CFR Part 60, Subparts KKKK.

E.2.2 New Source Performance Standards for Stationary Combustion Turbines Requirements [40 CFR Part 60, Subpart KKKK] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart KKKK, the Permittee shall comply with the provisions of New Source Performance Standards for Stationary Combustions Turbines, which are incorporated by reference as 326 IAC 12, for the two (2) natural gas combustion turbines EU-1 and EU-2 and two (2) duct burners associated with the heat recovery steam generators as specified as follows:

1. 40 CFR 60.4300
2. 40 CFR 60.4305
3. 40 CFR 60.4320
4. 40 CFR 60.4330(a)(1) or (2)
5. 40 CFR 60.4333
6. 40 CFR 60.4340(b)(1)
7. 40 CFR 60.4345
8. 40 CFR 60.4350(a)-(e), (f)(1)-(2), (h)
9. 40 CFR 60.4360
10. 40 CFR 60.4365
11. 40 CFR 60.4370(b), (c)
12. 40 CFR 60.4375(a)
13. 40 CFR 60.4380(b)
14. 40 CFR 60.4385(a), (c)
15. 40 CFR 60.4395
16. 40 CFR 60.4400(a), (b)(2), (b)(4)-(6)
17. 40 CFR 60.4405
18. 40 CFR 60.4415
19. 40 CFR 60.4420

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(l) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

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

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

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the natural gas fired auxiliary boiler, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

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

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

1. **40 CFR 60.40c(a)-(d)**
2. **40 CFR 60.41c**
3. **40 CFR 60.48c(a)(1), (3)**
4. **40 CFR 60.48c(g),(i)**

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(d) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

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

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

E.4.1 General Provisions Relating to NSPS IIII [326 IAC 12][40 CFR Part 60, Subpart A]

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

E.4.2 Standards of Performance for Stationary Compression Ingnition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

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

The emergency fire pump engine is subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. **40 CFR 60.4200(a)(2)(ii)**
2. **40 CFR 60.4202(d)**
3. **40 CFR 60.4205(c)**
4. **40 CFR 60.4206**
5. **40 CFR 60.4207**
6. **40 CFR 60.4211(a), (c)**
7. **40 CFR 60.4218**
8. **40 CFR 60.4219**

The emergency diesel generator is subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. **40 CFR 60.4200(a)(2)(i)**
2. **40 CFR 60.4202(a)(2)**
3. **40 CFR 60.4205(b)**
4. **40 CFR 60.4206**
5. **40 CFR 60.4207**
6. **40 CFR 60.4211(a), (c)**
7. **40 CFR 60.4218**

8. 40 CFR 60.4219

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(d) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

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

National Emissions Standard for Hazardous Air Pollutants [326 IAC 20] [40 CFR 63, Subpart ZZZZ]

E.5.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [326 IAC 20-1][40 CFR Part 63, Subpart A]

Pursuant to 40 CFR 63.6590, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 for the affected source, as specified in Appendix A of 40 CFR Part 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR 63 Subpart ZZZZ.

E.5.2 National Emissions Standard for Hazardous Air Pollutants for stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ][326 IAC 20-82-1]

Pursuant to CFR Part 63, Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR Part 63.6590, for the affected source, as specified as follows:

1. 40 CFR 63.6590
2. 40 CFR 63.6645

SECTION F RESERVED ~~Nitrogen Oxides Budget Trading Program - NO_x Budget Permit for NO_x Budget Units Under 326 IAC 10-4-1(a)~~

~~**ORIS Code: 991**~~

~~**NO_x Budget Source [326 IAC 2-7-5(15)]**~~

~~(a) Two (2) no. 2 fuel oil fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.~~

~~(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_x and SO_2 and a continuous opacity monitor (COM).~~

~~(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_x burners (LNB) for control of NO_x emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_x and SO_2 and a continuous opacity monitor (COM).~~

~~(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB for control of NO_x emissions, which were voluntarily installed and are not required to operate. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_x and SO_2 and a continuous opacity monitor (COM).~~

~~(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) for control of NO_x emissions, which was voluntarily installed and is not required to operate. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_x burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_x and SO_2 and a continuous opacity monitor (COM).~~

~~(The information contained in this box is descriptive information and does not constitute enforceable conditions.)~~

~~F.1 Automatic Incorporation of Definitions [326 IAC 10-4-7(e)]~~

~~This NO_x budget permit is deemed to incorporate automatically the definitions of terms under 326 IAC 10-4-2.~~

~~F.2 Standard Permit Requirements [326 IAC 10-4-4(a)]~~

~~(a) The owners and operators of the NO_x budget source and each budget unit shall operate each unit in compliance with this NO_x budget permit.~~

~~(b) The NO_x budget units subject to this NO_x budget permit are Units 1, 2, 3, 4, 5 and 6.~~

~~F.3 Monitoring Requirements [326 IAC 10-4-4(b)]~~

~~(a) The owners and operators and, to the extent applicable, the NO_x authorized account representative of the NO_x budget source and each NO_x budget unit at the source shall comply with the monitoring requirements of 40 CFR 75 and 326 IAC 10-4-12.~~

~~(b) The emissions measurements recorded and reported in accordance with 40 CFR 75 and 326 IAC 10-4-12 shall be used to determine compliance by each unit with the NO_x budget emissions limitation under 326 IAC 10-4-4(c) and Condition F.4, Nitrogen Oxides Requirements.~~

~~F.4 Nitrogen Oxides Requirements [326 IAC 10-4-4(c)]~~

~~(a) The owner and operators of the NO_x budget source and each NO_x budget unit at the source shall hold NO_x allowances available for compliance deductions under 326 IAC 10-4-10(j), as of the NO_x allowance transfer deadline, in each boiler's compliance account and the source's overdraft account in an amount:~~

~~(1) Not less than the total NO_x emissions for the ozone control period from the unit, as determined in accordance with 40 CFR 75 and 326 IAC 10-4-12;~~

~~(2) To account for excess emissions for a prior ozone control period under 326 IAC 10-4-10(k)(5); or~~

~~(3) To account for withdrawal from the NO_x budget trading program, or a change in regulatory status of a NO_x budget opt-in unit.~~

~~(b) Each ton of NO_x emitted in excess of the NO_x budget emissions limitation shall constitute a separate violation of the Clean Air Act (CAA) and 326 IAC 10-4.~~

~~(c) NO_x allowances shall be held in, deducted from, or transferred among NO_x allowance tracking system accounts in accordance with 326 IAC 10-4-9 through 11, 326 IAC 10-4-13, and 326 IAC 10-4-14.~~

~~(d) A NO_x allowance shall not be deducted, in order to comply with the requirements under (a) above and 326 IAC 10-4-4(c)(1), for an ozone control period in a year prior to the year for which the NO_x allowance was allocated.~~

~~(e) A NO_x allowance allocated under the NO_x budget trading program is a limited authorization to emit one (1) ton of NO_x in accordance with the NO_x budget trading program. No provision of the NO_x budget trading program, the NO_x budget permit application, the NO_x budget permit, or an exemption under 326 IAC 10-4-3 and no provision of law shall be construed to limit the authority of the U.S. EPA or IDEM, OAQ to terminate or limit the authorization.~~

~~(f) A NO_x allowance allocated under the NO_x budget trading program does not constitute a property right.~~

~~(g) Upon recordation by the U.S. EPA under 326 IAC 10-4-10, 326 IAC 10-4-11, or 326 IAC 10-4-13, every allocation, transfer, or deduction of a NO_x allowance to or from each NO_x budget unit's compliance account or the overdraft account or the overdraft account of the source where the unit is located is deemed to amend automatically, and become a part of, this NO_x budget permit of the NO_x budget unit by operation of law without any further review.~~

~~F.5 Excess Emissions Requirements [326 IAC 10-4-4(d)]~~

~~The owners and operators of each NO_x budget unit that has excess emissions in any ozone control period shall do the following:~~

~~(a) Surrender the NO_x allowances required for deduction under 326 IAC 10-4-10(k)(5).~~

~~(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed under 326 IAC 10-4-10(k)(7).~~

~~F.6 Record Keeping Requirements [326 IAC 10-4-4(e)] [326 IAC 2-7-5(3)]~~

~~Unless otherwise provided, the owners and operators of the NO_x budget source and each NO_x budget unit at the source shall keep, either on site at the source or at a central location within Indiana for unattended sources, each of the following documents for a period of five (5) years:~~

~~(a) The account certificate of representation for the NO_x authorized account representative for the source and each NO_x budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 326 IAC 10-4-6(h). The certificate and documents shall be retained either on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond the five (5) year period until the documents are superseded because of the submission of a new account certificate of representation changing the NO_x authorized account representative.~~

~~(b) All emissions monitoring information, in accordance with 40 CFR 75 and 326 IAC 10-4-12, provided that to the extent that 40 CFR 75 and 326 IAC 10-4-12 provide for a three (3) year period for record keeping, the three (3) year period shall apply.~~

~~(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_x budget trading program.~~

~~(d) Copies of all documents used to complete a NO_x budget permit application and any other submission under the NO_x budget trading program or to demonstrate compliance with the requirements of the NO_x budget trading program.~~

~~This period may be extended for cause, at any time prior to the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Records retained at a central location within Indiana shall be available immediately at the location and submitted to IDEM, OAQ or U.S. EPA within three (3) business days following receipt of a written request. Nothing in 326 IAC 10-4-4(e) shall alter the record retention requirements for a source under 40 CFR 75. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.~~

~~F.7 Reporting Requirements [326 IAC 10-4-4(e)]~~

~~(a) The NO_x authorized account representative of the NO_x budget source and each NO_x budget unit at the source shall submit the reports and compliance certifications required under the NO_x budget trading program, including those under 326 IAC 10-4-8, 326 IAC 10-4-12, or 326 IAC 10-4-13.~~

~~(b) Pursuant to 326 IAC 10-4-4(e) and 326 IAC 10-4-6(e)(1), each submission shall include the following certification statement by the NO_x authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the NO_x budget sources or NO_x budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."~~

~~(c) Where 326 IAC 10-4 requires a submission to IDEM, OAQ, the NO_x authorized account representative shall submit required information to:~~

~~Indiana Department of Environmental Management~~
~~Office of Air Quality~~
~~100 North Senate Avenue~~
~~MC 61-53, IGCN Room 1003~~
~~Indianapolis, Indiana 46204-2251~~

~~(d) Where 326 IAC 10-4 requires a submission to U.S. EPA, the NO_x authorized account representative shall submit required information to:~~

~~U.S. Environmental Protection Agency~~
~~Clean Air Markets Division~~
~~1200 Pennsylvania Avenue, NW~~
~~Mail Code 6204N~~
~~Washington, DC 20460~~

~~F.8 Liability [326 IAC 10-4-4(f)]~~

~~The owners and operators of each NO_x budget source shall be liable as follows:~~

~~(a) Any person who knowingly violates any requirement or prohibition of the NO_x budget trading program, a NO_x budget permit, or an exemption under 326 IAC 10-4-3 shall be subject to enforcement pursuant to applicable state or federal law.~~

~~(b) Any person who knowingly makes a false material statement in any record, submission, or report under the NO_x budget trading program shall be subject to criminal enforcement pursuant to the applicable state or federal law.~~

~~(c) No permit revision shall excuse any violation of the requirements of the NO_x budget trading program that occurs prior to the date that the revision takes effect.~~

~~(d) Each NO_x budget source and each NO_x budget unit shall meet the requirements of the NO_x budget trading program.~~

~~(e) Any provision of the NO_x budget trading program that applies to a NO_x budget source, including a provision applicable to the NO_x authorized account representative of a NO_x budget source, shall also apply to the owners and operators of the source and the NO_x budget units at the source.~~

~~(f) Any provision of the NO_x budget trading program that applies to a NO_x budget unit, including a provision applicable to the NO_x authorized account representative of a NO_x budget unit, shall also apply to the owners and operators of the unit. Except with regard to the requirements applicable to units with a common stack under 40 CFR 75 and 326 IAC 10-4-12, the owners and operators and the NO_x authorized account representative of one (1) NO_x budget unit shall not be liable for any violation by any other NO_x budget unit of which they are not owners or operators or the NO_x authorized account representative and that is located at a source of which they are not owners or operators or the NO_x authorized account representative.~~

~~F.9 Effect on Other Authorities [326 IAC 10-4-4(g)]~~

~~No provision of the NO_x budget trading program, a NO_x budget permit application, a NO_x budget permit, or an exemption under 326 IAC 10-4-3 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NO_x authorized account representative a NO_x budget source or NO_x budget unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the CAA.~~

SECTION G Clean Air Interstate Rule (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

ORIS Code: 991

CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

(a) Two (2) no. 2 fuel oil fired boilers, identified as Unit 1 and Unit 2, constructed in 1949 and 1950, respectively, each with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), both exhausting to stack 1-1.

(b) One (1) tangentially-fired wet-bottom coal boiler, identified as Unit 3, constructed in 1951, with a design heat input capacity of 524 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 3 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite and used oil contaminated materials generated onsite may be combusted in Unit 3 as supplemental fuel for energy recovery. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(c) One (1) tangentially-fired dry-bottom coal fired boiler, identified as Unit 4, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 2-1. Unit 4 is equipped with separated overfire air (SOFA) and low NO_X burners (LNB) for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 4 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 2-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(d) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 5, constructed in 1953, with a design heat input capacity of 741 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) and flue gas conditioning system for control of particulate matter, exhausting to stack 3-1. Unit 5 is equipped with SOFA and LNB for control of NO_X emissions, which were voluntarily installed and are not required to operate. Unit 5 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

(e) One (1) tangentially-fired dry-bottom coal boiler, identified as Unit 6, constructed in 1956, with a design heat input capacity of 1017 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, exhausting to stack 3-1. Unit 6 is equipped with Closed-coupled Overfire Air (COFA) for control of NO_X emissions, which was voluntarily installed and is not required to operate. Unit 6 will combust no. 2 fuel oil during startup, shutdown, and stabilization periods. Used oil generated onsite may be combusted in Unit 6 as supplemental fuel for energy recovery. Unit 6 has had low-NO_X burners installed. Stack 3-1 has continuous emission monitoring systems (CEMS) for NO_X and SO_2 and a continuous opacity monitor (COM).

<u>The New Combined Cycle Combustion Turbine Generation Facility Emission Units:</u>

(k) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

***Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in**

conjunction with the duct burners and combustion turbines which are a source of emissions.

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

G.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)] [326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-1-2, 326 IAC 24-2-2, and 326 IAC 24-3-2.

G.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]

(a) The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall operate each source and unit in compliance with this CAIR permit.

(b) The CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units subject to this CAIR permit are Units 1, 2, 3, 4, 5 and 6.

G.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall comply with the applicable monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source with the CAIR NO_X emissions limitation under 326 IAC 24-1-4(c), CAIR SO_2 emissions limitation under 326 IAC 24-2-4(c), and CAIR NO_X ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition G.4.1, Nitrogen Oxides Emission Requirements, Condition G.4.2, Sulfur Dioxide Emission Requirements, and Condition G.4.3, Nitrogen Oxides Ozone Season Emission Requirements.

G.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 326 IAC 24-1-11.

(b) A CAIR NO_X unit shall be subject to the requirements under 326 IAC 24-1-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-1-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X allowance shall not be deducted for compliance with the requirements under 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(d) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X annual trading program. No provision of the CAIR NO_X annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in this CAIR permit.

G.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR SO_2 unit shall be subject to the requirements under 326 IAC 24-2-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-2-4(c)(2), and for each control period thereafter.

(c) A CAIR SO_2 allowance shall not be deducted for compliance with the requirements under 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(d) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

(e) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 trading program. No provision of the CAIR SO_2 trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR SO_2 allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in this CAIR permit.

G.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of the each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit at the source shall hold, in the source's compliance account, CAIR NO_X ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.

(b) A CAIR NO_X ozone season unit shall be subject to the requirements under 326 IAC 24-3-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-3-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X ozone season allowance shall not be deducted for compliance with the requirements under 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X ozone season allowance was allocated.

(d) CAIR NO_X ozone season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.

(e) A CAIR NO_X ozone season allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X ozone season trading program. No provision of the CAIR NO_X ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X ozone season allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR NO_X ozone season allowance to or from a CAIR NO_X ozone season source's compliance account is incorporated automatically in this CAIR permit.

G.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]

(a) The owners and operators of a CAIR NO_X source and each CAIR NO_X unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation shall do the following:

(1) Surrender the CAIR NO_X allowances required for deduction under 326 IAC 24-1-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-1-4, the Clean Air Act (CAA), and applicable state law.

(b) The owners and operators of a CAIR SO_2 source and each CAIR SO_2 unit that emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation shall do the following:

(1) Surrender the CAIR SO_2 allowances required for deduction under 326 IAC 24-2-8(k)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-2-4, the Clean Air Act (CAA), and applicable state law.

(c) The owners and operators of a CAIR NO_X ozone season source and each CAIR NO_X ozone season unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X ozone season emissions limitation shall do the following:

(1) Surrender the CAIR NO_X ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-3-4, the Clean Air Act (CAA), and applicable state law.

G.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

(a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

(d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program or to demonstrate compliance with the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

This period may be extended for cause, at any time before the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

G.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall submit the reports required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the information 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

(d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the information shall be submitted to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

G.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]

The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall be liable as follows:

(a) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall meet the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, respectively.

(b) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source.

(c) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit or the CAIR designated representative of a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall also apply to the owners and operators of such unit.

G.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]

No provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

G.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-1-6, 326 IAC 24-2-6, and 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), 326 IAC 24-3-6(f)(3), each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source, including all CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program concerning the source or any CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source.

(b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source choose to designate an alternate CAIR designated representative.

Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), 326 IAC 24-3-6(f)(3), whenever the term "CAIR designated representative" is used, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

Change 5: New reporting forms have been added to the permit and some of the reporting forms will be deleted after the removal of the boilers.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Mailing Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Units 1, 2, and PR-10
Parameter: SO_2 Emissions
Limit: Shall not exceed the pound per million Btu (lb/MMBtu) limit, demonstrated using a calendar month average

YEAR: _____

Emission Unit	Limit (lb/MMBtu)	SO_2 Emissions (lb/MMBtu)		
		Month:	Month:	Month:
Unit 1	0.37			
Unit 2	0.37			
Unit PR-10	0.5			

☐ No deviation occurred in this quarter.

☐ Deviations occurred in this quarter.
Deviation has been reported on: ____________________

Submitted By: ________________________________

Title/Position: ________________________________

Signature: ________________________________

Date: ________________________________

Phone: ________________________________

Attach a signed certification to complete this report.

Note: **<u>The Part 70 quarterly reporting form shall no longer apply to the distillate fuel oil fired generator, identified as PR-10 and the two No. 2 fuel oil fired boilers identified as Units 1 and 2 after the emission units have been shut down and decommissioned.</u>**

~~INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT~~
~~OFFICE OF AIR QUALITY~~
~~COMPLIANCE DATA SECTION~~
~~Part 70 Quarterly Report~~

~~Source Name:~~ ~~Indianapolis Power and Light (IPL) Eagle Valley Generating Station~~
~~Source Address:~~ ~~4040 Blue Bluff Road, Martinsville, IN 46151~~
~~Mailing Address:~~ ~~4040 Blue Bluff Road, Martinsville, IN 46151~~
~~Part 70 Permit No.:~~ ~~T 109-26292-00004~~
~~Facility:~~ ~~Units 3, 4, 5, and 6~~
~~Parameter:~~ ~~SO_2 Emissions~~
~~Limit:~~ ~~Shall not exceed the pound per million Btu (lb/MMBtu) limit, demonstrated using a 30-day rolling average~~

~~YEAR:~~ ______ ~~QUARTER:~~ ______

~~Date~~	~~Limit (lb/MMBtu)~~	~~Daily Average~~	~~Weight Factor~~	~~30-day Rolling Average~~	~~Remarks~~
~~1.~~					
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~~29.~~					
~~30.~~					

☐ ~~No deviation occurred in this quarter.~~

☐ ~~Deviations occurred in this quarter.~~
~~Deviation has been reported on:~~ ______________________

~~Submitted By:~~ ______________________________________

~~Title/Position:~~ ______________________________

~~Signature:~~ ______________________________

~~Date:~~ ______________________________

~~Phone:~~ ______________________________

~~Attach a signed certification to complete this report.~~

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

Part 70 Quarterly Report

Source Name: **Indianapolis Power and Light (IPL) Eagle Valley Generating Station**
Source Address: **4040 Blue Bluff Road, Martinsville, IN 46151**
Part 70 Permit No.: **T 109-26292-00004**
Facility: **Combined Cycle Combustion Turbines EU-1 - EU-2**
Parameter: **NOx Emissions**
Limit: **shall not exceed 68 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.**

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________

Phone: ____

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

Part 70 Quarterly Report

Source Name: **Indianapolis Power and Light (IPL) Eagle Valley Generating Station**
Source Address: **4040 Blue Bluff Road, Martinsville, IN 46151**
Part 70 Permit No.: **T 109-26292-00004**
Facility: **Combined Cycle Combustion Turbines EU-1 - EU-2**
Parameter: **CO Emissions**
Limit: **shall not exceed 565 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.**

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: ______________________________________
Title / Position:______________________________________
Signature:____
Date: ____
Phone: ____

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbines EU-1 - EU-2
Parameter: VOC Emissions
Limit: shall not exceed 146 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbine EU-1 - EU-2
Parameter: CO2e
Limit: shall not exceed 2,649,570 tons per twelve (12) consecutive month period
with compliance determined at the end of each month.

QUARTER : **YEAR:**

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Auxiliary Boiler EU-3
Parameter: CO2e
Limit: shall not exceed 40,639 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Dew Point Heater EU-4
Parameter: CO2e
Limit: shall not exceed 10,569 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: ______________________________
Title / Position:______________________________
Signature:______________________________
Date: ______________________________
Phone: ______________________________________

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

Part 70 Quarterly Report

Source Name: **Indianapolis Power and Light (IPL) Eagle Valley Generating Station**
Source Address: **4040 Blue Bluff Road, Martinsville, IN 46151**
Part 70 Permit No.: **T 109-26292-00004**
Facility: **Emergency Generator EU-5**
Parameter: **CO_2e**
Limit: **shall not exceed 605 tons per twelve (12) consecutive month period with compliance determined at the end of each month.**

QUARTER : **YEAR:**

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

Month 1			
Month 2			
Month 3			

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name:	**Indianapolis Power and Light (IPL) Eagle Valley Generating Station**
Source Address:	**4040 Blue Bluff Road, Martinsville, IN 46151**
Part 70 Permit No.:	**T 109-26292-00004**
Facility:	**Fire Pump Engine EU-6**
Parameter:	**CO2e**
Limit:	**shall not exceed 157.5 tons per twelve (12) consecutive month period with compliance determined at the end of each month.**

QUARTER : **YEAR:**

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

Month 3			

☐ **No deviation occurred in this quarter.**

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

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

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

Part 70 Quarterly Report

Source Name: Indianapolis Power and Light (IPL) Eagle Valley Generating Station
Source Address: 4040 Blue Bluff Road, Martinsville, IN 46151
Part 70 Permit No.: T 109-26292-00004
Facility: Combined Cycle Combustion Turbines EU-1 - EU-2
Parameter: Single HAPs Emissions (Formaldehyde)
Limit: less than 9 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

☐ **Deviation/s occurred in this quarter.**

Deviation has been reported on:

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

Other Changes

Upon further review IDEM, OAQ has made the following changes to the Title V permit T109-26292-00004. (deleted language appears as ~~strikeout~~ and the new language **bolded**):

Change 1: Upon re-designation of Morgan County as attainment Country on July 11, 2013, IDEM has revised Section A.2 - General Information with respect to the re-designation.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)] [326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

Source Address:	4040 Blue Bluff Road, Martinsville, Indiana, 46151
Mailing Address:	4040 Blue Bluff Road, Martinsville, Indiana, 46151
Source Telephone:	765-349-3413
SIC Code:	4911
County Location:	Morgan
County Status:	~~Nonattainment for $PM_{2.5}$~~ Attainment for all ~~other~~ criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules ~~and Nonattainment NSR~~; Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

Change 2: IDEM OAQ has replaced Condition C.11 - Compliance Monitoring with the updated version.

C.11 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

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

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

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

in writing, prior to the end of the initial ninety (90) day compliance schedule, with

full justification of the reasons for the inability to meet this date.

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

(c) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(d) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

~~Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, 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 the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).~~

~~Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.~~

Conclusion and Recommendation

The construction and operation of this proposed modification shall be subject to the conditions of the attached proposed PSD/Part 70 Significant Source Modification No. 109-32471-00004 and Significant Permit Modification No. 109-32476-00004. The staff recommends to the Commissioner that this Part 70 Significant Source and Significant Permit Modification be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5257 or toll free at 1-800-451-6027 extension 4-5257.

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

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

IPL Eagle Valley

	Emission Unit	MW output	MMBtu/hr
CT-1	EU-1	656 MW nominal capacity	*2463*
CT-1 w/ Duct Burner			*2542*
CT-2	EU-2		*2463*
CT-2 w/ Duct Burner			*2542*
Aux. Boiler	EU-3		*79.3*
Dew Point Heater	EU-4		*20.8*
		HP	MMBtu/hr
Fire Pump Engine	EU-5	*500*	*3.85*
Emergency generator	EU-6	*1826*	*14.8*

Basis for Emisison Factors

(yellow)	Proposed permit Limits Based On Vendor data
(green)	AP-42
(blue)	40 CFR Part 98; Tables A-1, C-1 and C-2

	Emission Factors													
	Units	NOx	CO	VOC	SO2	PM	PM10	PM2.5	H2SO4	Fluorides	Lead	Mercury	CO2	CH4	N2O
	ppmv	2	2	2											
per CT NG w duct firing	lbs/hr	18.9	14.4	8.99	3.55	16.78	16.78	16.78	2.06				306,306	5.60	0.56
	lbs/MMBtu				0.0014	0.0066	0.0066	0.0066	0.00081					2.20E-03	2.20E-04
per CT NG w/o duct firing	lbs/hr	18.6	11.3	3.25	3.45	13.55	13.55	13.55	1.47				301,647	5.43	0.54
	lbs/MMBtu				0.0014	0.0055	0.0055	0.0055	0.00060					2.20E-03	2.20E-04
Aux Boiler	lbs/MMBtu	0.011	0.082	0.0053	0.0014	0.005	0.005	0.005	0.000107			2.55E-07	117	2.20E-03	2.20E-04
	lbs/hr	0.87	6.50	0.42	0.11	0.40	0.40	0.40	0.00850			2.02E-05			
Dew Point Heater	lbs/MMBtu	0.032	0.082	0.0053	0.0014	0.0072	0.0072	0.0072	0.000107			2.55E-07	117	2.20E-03	2.20E-04
	lbs/hr	0.67	1.71	0.11	0.029	0.150	0.150	0.150	0.00223			5.30E-06			
Fire Pump Engine	lbs/MMBtu	0.831	0.745	0.029	0.0015	0.043	0.043	0.043	0.000115				163	6.61E-03	1.32E-03
	lbs/hr	3.20	2.87	0.11	0.0060	0.17	0.17	0.17	0.00044						
Emergency Generator	lbs/MMBtu	1.27	0.709	0.027	0.0015	0.043	0.043	0.043	0.000115				163	6.61E-03	1.32E-03
	lbs/hr	18.8	10.50	0.40	0.022	0.64	0.6	0.6	0.00170						
Lube Oil Demister Vents	lbs/hr/vent					0.0174	0.0174	0.0174							

Global Warming Potentials			
1	21	310	23,900

		Potential to Emit, Tons/Year																
Emission Unit	Hours/ Year	NOx	CO	VOC	SO2	PM	PM10	PM2.5	H2SO4	Fluorides	Lead	Mercury	CO2	CH4	N2O	SF6	CO2e	Total HAPs	Formalde-hyde
CT-1 w/duct firing	1000	9.5	7.2	4.5	1.8	8.4	8.4	8.4	1.0				153,153	2.80	0.28		153,299	1.27	0.90
CT-1 w/o duct firing	7760	72.2	43.8	12.6	13.4	52.6	52.6	52.6	5.7				1,170,390	21.07	2.11		1,171,486	9.54	6.79
CT-2 w/duct firing	1000	9.5	7.2	4.5	1.8	8.4	8.4	8.4	1.0				153,153	2.80	0.28		153,299	1.27	0.90
CT-2 w/o duct firing	7760	72.2	43.8	12.6	13.4	52.6	52.6	52.6	5.7				1,170,390	21.07	2.11		1,171,486	9.54	6.79
Auxiliary Boiler	8760	3.8	28.5	1.8	0.5	1.7	1.7	1.7	0.04			0.0001	40,599	0.77	0.08		40,639	0.72	0.028
Dew Point Heater	8760	2.92	7.47	0.48	0.13	0.66	0.66	0.66	0.010			0.000023	10,649	0.20	0.02		10,659	0.17	0.007
Fire Pump	500	0.80	0.72	0.03	0.0015	0.041	0.041	0.041					156.94	0.0064	0.0013		157.47	0.0037	0.001
Emergency Generator	500	4.70	2.63	0.10	0.01	0.16	0.15	0.15					603.29	0.0245	0.0049		605.32	0.0058	0.000
Cooling Towers	8760					10.5	6.7	0.020											
Paved Roads/Parking	8760					0.216	0.043	0.011											
Methane leaks	8760													69.85			1466.9		
Circuit Breakers	8760															0.0025	59.8		
3 Lube Oil vents	8760					0.229	0.229	0.229											
Totals		**175.5**	**141.4**	**36.7**	**30.9**	**135.4**	**131.5**	**124.7**	**13.5**	**0.0**	**0.000**	**0.00011**	**2,699,095**	**118.6**	**4.9**	**0.003**	**2,703,157**	**22.52**	**15.41**
CCCT Subtotal		**163.2**	**102.1**	**34.2**	**30.3**	**121.9**	**121.9**	**121.9**	**13.5**	**0.0**	**0.000**	**0.00**	**2,647,087**	**47.7**	**4.8**	**0.0**	**2,649,569**	**21.62**	**15.37**
SD/NNSR Significance Threshold, tons/ye		40	100	40	40	25	15	10	7	3	0.6	0.1	NA	NA	NA	NA	75,000		

Potential to Emit, 8760 Hours: Non-Normal Load Operation (cold, warm, hot starts and shutdown conditions)

Emission Unit	Events/ year	Minutes/ Event	Hours Down/ event	Hours/ year	Emission Rate, lbs/hour			PTE, tons/year		
					NOx	CO	VOC	NOx	CO	VOC
CT-1 @100% load w/ duct firing				1000	18.9	12.6	8.99	9.5	6.3	4.5
CT-1 @ 100% Load w/o duct firing				3863.0	18.4	11.2	3.25	35.5	21.6	6.3
CT-1 Cold Starts	*16*	*225*	*72*	60.0	114.3	904	265.8	3.4	27.1	8.0
CT-1 Warm Starts	*260*	*119*	*8*	515.7	111	950.5	242.5	28.6	245.1	62.5
CT-1 Hot Starts	*10*	*50*	*0*	8.3	41.4	370.6	60.3	0.2	1.5	0.3
CT-1 Shutdown	*286*	*17*		81.0	37.9	218.3	60.4	1.5	8.8	2.4
CT-1 Annual Total								78.7	310.5	84.0
CT-2 @100% load w/ duct firing				1000	18.9	12.6	8.99	9.5	6.3	4.5
CT-2 @ 100% Load w/o duct firing				3863.0	18.4	11.2	3.25	35.5	21.6	6.3
CT-2 Cold Starts	*16*	*225*	*72*	60.0	114.3	904	265.8	3.4	27.1	8.0
CT-2 Warm Starts	*260*	*119*	*8*	515.7	111	950.5	242.5	28.6	245.1	62.5
CT-2 Hot Starts	*10*	*50*	*0*	8.3	41.4	370.6	60.3	0.2	1.5	0.3
CT-2 Shutdown	*286*	*17*		81.0	37.9	218.3	60.4	1.5	8.8	2.4
CT-2 Annual Total								78.7	310.5	84.0
CT-1 & CT-2 Total								157.5	621.0	167.9
CT-1 & CT-2 Startup Shutdown Total								67.5	565.2	146.4

	Emissions per event, lbs		
	NOx	CO	VOC
Cold Start	428.6	3390.0	996.8
Warm Start	220.2	1885.2	481.0
Hot Start	34.5	308.8	50.3
Shut Down	10.7	61.9	17.1

Potential to Emit, 8760 Hours: Non-Normal Load Operation (cold, warm, hot starts and shutdown conditions) Cas

Emission Unit	Events/ year	Minutes/ Event	Hours Down/ event	Hours/ year	Emission Rate, lbs/hour			PTE, tons/year		
					NOx	CO	VOC	NOx	CO	VOC
CT-1 @100% load w/ duct firing				1000	18.9	12.6	8.99	9.5	6.3	4.5
CT-1 @ 100% Load w/o duct firing				4072.3	18.4	11.2	3.25	37.5	22.8	6.6
CT-1 Cold Starts	*5*	*229*	*72*	19.1	114.3	1295	1686	1.1	12.4	16.1
CT-1 Warm Starts	*260*	*123*	*10*	533.0	111	1363	1538	29.6	363.2	409.9
CT-1 Hot Starts	*10*	*71*	*4*	11.8	41.4	527.7	794	0.2	3.1	4.7
CT-1 Shutdown	*275*	*27*		123.8	37.9	245.8	671	2.3	15.2	41.5
CT-1 Annual Total								80.2	423.0	483.3
CT-2 @100% load w/ duct firing				1000	18.9	12.6	8.99	9.5	6.3	4.5
CT-2 @ 100% Load w/o duct firing				4072.3	18.4	11.2	3.25	37.5	22.8	6.6
CT-2 Cold Starts	*5*	*229*	*72*	19.1	114.3	1295	1686	1.1	12.4	16.1
CT-2 Warm Starts	*260*	*123*	*10*	533.0	111	1363	1538	29.6	363.2	409.9
CT-2 Hot Starts	*10*	*71*	*4*	11.8	41.4	527.7	794	0.2	3.1	4.7
CT-2 Shutdown	*275*	*27*		123.8	37.9	245.8	671	2.3	15.2	41.5
CT-2 Annual Total								80.2	423.0	483.3
CT-1 & CT-2 Total								160.4	**846.1**	**966.6**
CT-1 & CT-2 Startup Shutdown Tota								66.5	**787.9**	**944.4**

Emission Reductions From Shutdown of Existing Units 1-6 (based on 2010 and 2011 Actual Emissions

Basis for Emission Factors

	CEMs Data
	AP-42
	40 CFR Part 98
	Stack Test Data
	Mass balance

644,000 tons coal in 2010
538,000 tons coal in 2011

Coal Heating Value 11,200 BTU/lb
Fuel Oil Heating Value 140,000 Btu/gal

Global Warming Potentials		
1	21	310

Emission Unit	Units	Emission Factors, lbs/MMBtu																
		NOx	CO	VOC	SO2	CPM	PM, filt, Controlled	PM10, filt, Controlled	PM10 Total, Controlled	PM2.5, filt, controlled	PM2.5, Total Controlled	H2SO4	Fluorides	Lead	Mercury	CO2	CH4	N20
Boiler 1 (Oil)	lbs/MMBtu	CEMs Data	*0.0357*	*0.00543*	CEMs Data	*0.00929*	*0.0143*	*0.0071*	*0.0164*	*0.0017*	*0.0110*	*0.00249*		*9.00E-06*	*3.00E-06*	CEMS Data	*0.00661*	*0.00132*
Boiler 2 (Oil)			*0.0357*	*0.00543*		*0.00929*	*0.0143*	*0.0071*	*0.0164*	*0.0017*	*0.0110*	*0.00249*		*9.00E-06*	*3.00E-06*		*0.00661*	*0.00132*
Boiler 3 (Coal) Wet Bottom			*0.0223*	*0.0018*		*0.196*	*0.058*	0.0435	0.2395	0.0232	0.2192	0.014	*0.0067*	*1.88E-05*	*3.71E-06*		*0.02425*	*0.00353*
Boiler 4 (Coal) Dry Bottom			*0.0223*	*0.0027*		*0.196*	*0.058*	0.03886	0.23486	0.01682	0.21282	0.014	*0.0067*	*1.88E-05*	*3.71E-06*		*0.02425*	*0.00353*
Boiler 5 (Coal) Dry Bottom			*0.0223*	*0.0027*		*0.196*	*0.085*	0.05695	0.25295	0.02465	0.22065	0.014	*0.0067*	*1.88E-05*	*3.71E-06*		*0.02425*	*0.00353*
Boiler 6 (Coal) Dry Bottom			*0.0223*	*0.0027*		*0.196*	*0.085*	0.05695	0.25295	0.02465	0.22065	0.014	*0.0067*	*1.88E-05*	*3.71E-06*		*0.02425*	*0.00353*

Emission Unit	MMBtu/year	2010 Annual Emissions, Tons																		
		NOx	CO	VOC	SO2	CPM	PM, filt, Controlled	PM10, filt, Controlled	PM10 Total, Controlled	PM2.5, filt, controlled	PM2.5, Total Controlled	H2SO4	Fluorides	Lead	Mercury	CO2	CH4	N20	CO2e	MW-hr Output
Boiler 1 (Oil)	40,435	2.10	0.72	0.11	0.7	0.19	0.29	0.14	0.33	0.035	0.22	0.050		0.00018	0.00006	3,282	0.13	0.03	3,293	2,893
Boiler 2 (Oil)	40,049	2.80	0.72	0.11	0.7	0.19	0.29	0.14	0.33	0.034	0.22	0.050		0.00018	0.00006	3,248	0.13	0.03	3,259	2,853
Boiler 3 (Coal)	1,222,378	798.40	13.64	1.09	4,199.3	119.8	35.4	26.6	146.4	14.2	134.0	8.6	4.1	0.0115	0.0023	436,495	14.82	2.16	439,905	123,048
Boiler 4 (Coal)	3,031,974		33.84	4.06		297.1	87.9	58.9	356.0	25.5	322.6	21.2	10.2	0.0284	0.0056		36.76	5.35		305,207
Boiler 5 (Coal)	2,833,621	964.00	31.63	3.80	8,065.0	277.7	120.4	80.7	358.4	34.9	312.6	19.8	9.5	0.0266	0.0052	806,346	34.36	5.00	812,644	304,674
Boiler 6 (Coal)	5,025,518		56.09	6.73		492.5	213.6	143.1	635.6	61.9	554.4	35.2	16.8	0.0471	0.0093		60.94	8.86		540,349
Totals		1,767.3	136.6	15.9	12,265.7	1,187.5	458.0	309.6	1,497.1	136.6	1,324.1	84.9	40.6	0.11	0.023	1,249,371	147.1	21.4	1,259,101	1,279,024

Emission Unit	Rated capacity, MMBtu/hr	20111 Annual Emissions, Tons NOx	CO	VOC	SO2	CPM	PM, filt, Controlled	PM10, filt, Controlled	PM10 Total, Controlled	PM2.5, filt, controlled	PM2.5, Total Controlled	H2SO4	Fluorides	Lead	Mercury	CO2	CH4	N20	CO2e	MW-hr Output
Boiler 1 (Oil)	19,636	1.1	0.35	0.053	0.300	0.09	0.14	0.070	0.161	0.017	0.108	0.024		0.000088	0.000029	1,593.1	0.065	0.013	1,598	1,336
Boiler 2 (Oil)	20,531	1.5	0.37	0.056	0.300	0.10	0.15	0.073	0.169	0.018	0.113	0.026		0.000092	0.000031	1,665.5	0.068	0.014	1,671	1,434
Boiler 3 (Coal)	1,338,811	838.2	14.94	1.20	4,153.9	131.20	38.83	29.12	160.32	15.53	146.73	9.37	4.5	0.0126	0.0025	422,848.4	16.23	2.36	426,151	134,160
Boiler 4 (Coal)	2,782,533		31.06	3.73		272.69	80.69	54.06	326.75	23.40	296.09	19.48	9.3	0.0261	0.0052		33.74	4.91		278,833
Boiler 5 (Coal)	1,989,529	955.1	22.20	2.66	6,720.2	194.97	84.55	56.65	251.63	24.52	219.49	13.93	6.7	0.0187	0.0037	691,367.6	24.12	3.51	696,768	202,182
Boiler 6 (Coal)	4,748,933		53.00	6.36		465.40	201.83	135.23	600.62	58.53	523.93	33.24	15.9	0.0445	0.0088		57.58	8.38		482,601
Totals		1,795.9	121.9	14.1	10,874.7	1,064.4	406.2	275.2	1,339.7	122.0	1,186.5	76.1	36.4	0.102	0.020	1,117,474.6	131.8	19.2	1,126,188	1,100,546
2010/2011 Average Emissions, tons		**1,782**	**129.3**	**15.0**	**11,570**	**1,126**	**432**	**292**	**1,418**	**129**	**1,255**	**80.5**	**38.5**	**0.108**	**0.021**	**1,183,423**	**139**	**20**	**1,192,644**	**1,189,785**

Project Net Emission Increase (Decrease) (Based on Basecase)		Emissions, tons/year NOx	CO	VOC	SO2	CPM	PM, filterable	PM10, filt, Controlled	PM10 Total	PM2.5, filt, controlled	PM2.5, Total	H2SO4	Fluorides	Lead	Mercury	CO2	CH4	N2O	SF6	CO2e
New equipment PTE		175.5	660.3	170.4	30.9		135.4		131.5		124.7	13.5	0.00000	0.000	0.000	2699095.0	118.6	4.9	0.003	2,703,157
Shutdown Credits		-1,782	-129	-15	-11,570		-432		-1,418		-1,255	-80	-38	-0.11	-0.021	-1,183,423	-139	-20	-1,192,644	-1,192,644
Net Emissions Increase/Decrease		-1,606	531.0	155	-11,539		-297		-1,287		-1,131	-67	-38	-0.11	-0.021	1,515,672	-21	-15	-1,192,644	1,510,513
PSD/NNSR Significance Threshold, tons/year		40	100	40	40	NA	25	NA	15	NA	10	7	3	0.6	0.1	NA	NA	NA	NA	75,000

	Tons/year NOx	CO	VOC	SO2	PM, filterable	PM10 Total	PM2.5, Total	H2SO4	Fluorides	Lead	Mercury	CO2e
New Equipment PTE	175.5	660.3	170.4	30.9	135.4	131.5	124.7	13.5	0.000	0.0000	0.0001	2,703,157
Reduction s from Shutdown of existing units	-1782	-129.3	-15.0	-11570	-432.1	-1418	-1255.3	-80.5	-38.5	-0.1080	-0.0214	-1,192,644
Net Emissions Change	-1606	531.0	155.4	-11539	-296.6	-1287	-1130.5	-67.0	-38.5	-0.1080	-0.0213	1,510,513
PSD/NNSR Significance Thresholds	40	100	40	40	25	15	10	7	3	0.6	0.1	75,000

1826 HP Emergency RICE	14.8 MMBtu/hr	
Diesel IC Engines > 600 HP, AP-42 Tables 3.4-2 and 3.4-3	lbs/MMBtu	Tons/year
Benzene	7.76E-04	2.87E-03
Toluene	2.81E-04	1.04E-03
Xylenes	1.93E-04	7.14E-04
Formaldehyde	7.89E-05	2.92E-04
Acetaldehyde	2.52E-05	9.32E-05
Acrolein	7.88E-06	2.92E-05
Naphthalene	1.30E-04	4.81E-04
Acenaphthylene	9.23E-06	3.42E-05
Acenaphthene	4.68E-06	1.73E-05
Fluorene	1.28E-05	4.74E-05
Phenanthrene	4.08E-05	1.51E-04
Anthracene	1.23E-06	4.55E-06
Fluoranthrene	4.03E-06	1.49E-05
Pyrene	3.71E-06	1.37E-05
Benz(a)anthracene	6.22E-07	2.30E-06
Chrysene	1.53E-06	5.66E-06
Benzo(b)fluoranthrene	1.11E-06	4.11E-06
Benzo(k)fluoranthrene	2.18E-07	8.07E-07
Benzo(a)pyrene	2.57E-07	9.51E-07
Indeno(1,2,3-cd)pyrene	4.14E-07	1.53E-06
Dibenz(a,h)anthracene	3.46E-07	1.28E-06
Benzo(g,h,l)perylene	5.56E-07	2.06E-06
Total	**1.57E-03**	**0.0058**

500 HP Fire Pump RICE	3.85 MMBtu/hr	
Diesel IC Engines < 600 HP, AP-42 Table 3.3-2	lbs/MMBtu	Tons/year
Benzene	9.33E-04	8.98E-04
Toluene	4.09E-04	3.94E-04
Xylenes	2.85E-04	2.74E-04
1,3-Butadiene	3.91E-05	3.76E-05
Formaldehyde	1.18E-03	1.14E-03
Acetaldehyde	7.67E-04	7.38E-04
Acrolein	9.25E-05	8.90E-05
Naphthalene	8.48E-05	8.16E-05
Acenaphthylene	5.06E-06	4.87E-06
Acenaphthene	1.42E-06	1.37E-06
Fluorene	2.92E-05	2.81E-05
Phenanthrene	2.94E-05	2.83E-05
Anthracene	1.87E-06	1.80E-06
Fluoranthrene	7.61E-06	7.32E-06
Pyrene	4.78E-06	4.60E-06
Benz(a)anthracene	1.68E-06	1.62E-06
Chrysene	3.53E-07	3.40E-07
Benzo(b)fluoranthrene	9.91E-08	9.54E-08
Benzo(k)fluoranthrene	1.55E-07	1.49E-07
Benzo(a)pyrene	1.88E-07	1.81E-07
Indeno(1,2,3-cd)pyrene	3.75E-07	3.61E-07
Dibenz(a,h)anthracene	5.83E-07	5.61E-07
Benzo(g,h,l)perylene	4.89E-07	4.71E-07
Total	3.87E-03	**0.0037**

Auxiliary Boiler	**79.3 MMBtu/hr**	
Natural Gas Fired Boilers AP-42 Tables 1.4-3 and 1.4-4	lbs/MMCF	Tons/year
Benzene	2.10E-03	7.97E-04
Toluene	3.40E-03	1.29E-03
Formaldehyde	7.50E-02	2.85E-02
1,3-Butadiene	3.91E-05	1.48E-05
Naphthalene	6.10E-04	2.31E-04
Acenaphthylene	1.80E-06	6.83E-07
Acenaphthene	1.80E-06	6.83E-07
Fluorene	2.80E-06	1.06E-06
Phenanthrene	1.70E-05	6.45E-06
Anthracene	2.40E-06	9.11E-07
Fluoranthrene	3.00E-06	1.14E-06
Pyrene	5.00E-06	1.90E-06
Benz(a)anthracene	1.80E-06	6.83E-07
Chrysene	1.80E-06	6.83E-07
Benzo(b)fluoranthrene	1.80E-06	6.83E-07
Benzo(k)fluoranthrene	1.80E-06	6.83E-07
Benzo(a)pyrene	1.20E-06	4.55E-07
Indeno(1,2,3-cd)pyrene	1.80E-06	6.83E-07
Dibenz(a,h)anthracene	1.20E-06	4.55E-07
Benzo(g,h,l)perylene	1.20E-06	4.55E-07
2 Methylnapthalene	2.50E-05	9.48E-06
3 methylcloranthene	1.60E-06	6.07E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	6.07E-06
Dichlorobenzene	1.20E-03	4.55E-04
Hexane	1.80E+00	6.83E-01
Arsenic	2.00E-04	7.59E-05
Barium	4.40E-03	1.67E-03
Beryllium	1.20E-05	4.55E-06
Cadmium	1.10E-03	4.17E-04
Chromium	1.40E-03	5.31E-04
Cobalt	8.40E-05	3.19E-05
Manganese	3.80E-04	1.44E-04
Mercury	2.60E-04	9.86E-05
Nickel	2.10E-03	7.97E-04
Selenium	2.40E-05	9.11E-06
Total HAPs	**1.89E+00**	**0.72**

Dew Point Heater	**20.8 MMBtu/hr**	
Natural Gas Fired Boilers AP-42 Tables 1.4-3 and 1.4-4	lbs/MMCF	Tons/year
Benzene	2.10E-03	1.88E-04
Toluene	3.40E-03	3.04E-04
Formaldehyde	7.50E-02	6.70E-03
1,3-Butadiene	3.91E-05	3.49E-06
Naphthalene	6.10E-04	5.45E-05
Acenaphthylene	1.80E-06	1.61E-07
Acenaphthene	1.80E-06	1.61E-07
Fluorene	2.80E-06	2.50E-07
Phenanthrene	1.70E-05	1.52E-06
Anthracene	2.40E-06	2.14E-07
Fluoranthrene	3.00E-06	2.68E-07
Pyrene	5.00E-06	4.47E-07
Benz(a)anthracene	1.80E-06	1.61E-07
Chrysene	1.80E-06	1.61E-07
Benzo(b)fluoranthrene	1.80E-06	1.61E-07
Benzo(k)fluoranthrene	1.80E-06	1.61E-07
Benzo(a)pyrene	1.20E-06	1.07E-07
Indeno(1,2,3-cd)pyrene	1.80E-06	1.61E-07
Dibenz(a,h)anthracene	1.20E-06	1.07E-07
Benzo(g,h,l)perylene	1.20E-06	1.07E-07
2 Methylnapthalene	2.50E-05	2.23E-06
3 methylcloranthene	1.60E-06	1.43E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.43E-06
Dichlorobenzene	1.20E-03	1.07E-04
Hexane	1.80E+00	1.61E-01
Arsenic	2.00E-04	1.79E-05
Barium	4.40E-03	3.93E-04
Beryllium	1.20E-05	1.07E-06
Cadmium	1.10E-03	9.82E-05
Chromium	1.40E-03	1.25E-04
Cobalt	8.40E-05	7.50E-06
Manganese	3.80E-04	3.39E-05
Mercury	2.60E-04	2.32E-05
Nickel	2.10E-03	1.88E-04
Selenium	2.40E-05	2.14E-06
Total HAPs	**1.89**	**0.17**

CT-1 w/o Duct Burner	2463	MMBtu/hr	7760	hrs/year
CT-1 w/ Duct Burner	2542	MMBtu/hr	1000	hrs/yr
CT-2 w/o Duct Burner	2463	MMBtu/hr	7760	hrs/year
CT-2 w/ Duct Burner	2542	MMBtu/hr	1000	hrs/yr

2 CT Units with Duct Burners		**Tons/Year PTE, Uncontrolled**					Tons/Year PTE @ 80% control
Natural Gas Fired Turbines AP-42 Table 3.1-3	lbs/MMBtu	CT-1 w/o Duct Burner	CT-1 w Duct Burner	CT-2 w/o Duct Burner	CT-2 w Duct Burner	Totals	
Benzene	1.20E-05	1.15E-01	1.53E-02	1.15E-01	1.53E-02	2.60E-01	5.20E-02
Toluene	1.30E-04	1.24E+00	1.65E-01	1.24E+00	1.65E-01	2.82E+00	5.63E-01
Xylenes	6.40E-05	6.12E-01	8.13E-02	6.12E-01	8.13E-02	1.39E+00	2.77E-01
Formaldehyde	7.10E-04	6.79E+00	9.02E-01	6.79E+00	9.02E-01	1.54E+01	3.07E+00
1,3-Butadiene	4.30E-07	4.11E-03	5.47E-04	4.11E-03	5.47E-04	9.31E-03	1.86E-03
Acetaldehyde	4.00E-05	3.82E-01	5.08E-02	3.82E-01	5.08E-02	8.66E-01	1.73E-01
Acrolein	6.40E-06	6.12E-02	8.13E-03	6.12E-02	8.13E-03	1.39E-01	2.77E-02
Ethylbenzene	3.20E-05	3.06E-01	4.07E-02	3.06E-01	4.07E-02	6.93E-01	1.39E-01
Naphthalene	1.30E-06	1.24E-02	1.65E-03	1.24E-02	1.65E-03	2.82E-02	5.63E-03
PAH	2.20E-06	2.10E-02	2.80E-03	2.10E-02	2.80E-03	4.76E-02	9.53E-03
Total HAPs	**9.98E-04**	**9.54**	**1.27**	**9.54**	**1.27**	**21.62**	**4.32**

Hazardous Air Pollutant	2 CTs with Duct Burners	Auxiliary Boiler	Dew Point Heater	Emergency Generator RICE	Fire Pump Rice	Project Totals
Benzene	2.60E-01	7.97E-04	1.88E-04	2.87E-03	8.98E-04	2.65E-01
Toluene	2.82E+00	1.29E-03	3.04E-04	1.04E-03	3.94E-04	2.82E+00
Formaldehyde	1.54E+01	2.85E-02	6.70E-03	2.92E-04	1.14E-03	1.54E+01
1,3-Butadiene	9.31E-03	1.48E-05	3.49E-06	NA	3.76E-05	9.37E-03
Naphthalene	1.30E-06	2.31E-04	5.45E-05	4.81E-04	8.16E-05	8.50E-04
Acenaphthylene	NA	6.83E-07	1.61E-07	3.42E-05	4.87E-06	3.99E-05
Acenaphthene	NA	6.83E-07	1.61E-07	1.73E-05	1.37E-06	1.95E-05
Fluorene	NA	1.06E-06	2.50E-07	4.74E-05	2.81E-05	7.68E-05
Phenanthrene	NA	6.45E-06	1.52E-06	1.51E-04	2.83E-05	1.87E-04
Anthracene	NA	9.11E-07	2.14E-07	4.55E-06	1.80E-06	7.48E-06
Fluoranthrene	NA	1.14E-06	2.68E-07	1.49E-05	7.32E-06	2.36E-05
Pyrene	NA	1.90E-06	4.47E-07	1.37E-05	4.60E-06	2.07E-05
Benz(a)anthracene	NA	6.83E-07	1.61E-07	2.30E-06	1.62E-06	4.76E-06
Chrysene	NA	6.83E-07	1.61E-07	5.66E-06	3.40E-07	6.84E-06
Benzo(b)fluoranthrene	NA	6.83E-07	1.61E-07	4.11E-06	9.54E-08	5.05E-06
Benzo(k)fluoranthrene	NA	6.83E-07	1.61E-07	8.07E-07	1.49E-07	1.80E-06
Benzo(a)pyrene	NA	4.55E-07	1.07E-07	9.51E-07	1.81E-07	1.69E-06
Indeno(1,2,3-cd)pyrene	NA	6.83E-07	1.61E-07	1.53E-06	3.61E-07	2.74E-06
Dibenz(a,h)anthracene	NA	4.55E-07	1.07E-07	1.28E-06	5.61E-07	2.40E-06
Benzo(g,h,l)perylene	NA	4.55E-07	1.07E-07	2.06E-06	4.71E-07	3.09E-06
2 Methylnapthalene	NA	9.48E-06	2.23E-06	NA	NA	1.17E-05
3 methylcloranthene	NA	6.07E-07	1.43E-07	NA	NA	7.50E-07
7,12-Dimethylbenz (a)anthracene	NA	6.07E-06	1.43E-06	NA	NA	7.50E-06
Dichlorobenzene	NA	4.55E-04	1.07E-04	NA	NA	5.62E-04
Hexane	NA	6.83E-01	1.61E-01	NA	NA	8.44E-01
Acetaldehyde	8.66E-01	NA	NA	9.32E-05	7.38E-04	8.67E-01
Acrolein	1.39E-01	NA	NA	2.92E-05	8.90E-05	1.39E-01
Ethylbenzene	6.93E-01	NA	NA			6.93E-01
Xylenes	1.39E+00	NA	NA	7.14E-04	2.74E-04	1.39E+00
PAH	4.76E-02	NA	NA	NA	NA	4.76E-02
Arsenic	NA	7.59E-05	1.79E-05	NA	NA	9.37E-05
Barium	NA	1.67E-03	3.93E-04	NA	NA	2.06E-03
Beryllium	NA	4.55E-06	1.07E-06	NA	NA	5.62E-06
Cadmium	NA	4.17E-04	9.82E-05	NA	NA	5.16E-04
Chromium	NA	5.31E-04	1.25E-04	NA	NA	6.56E-04
Cobalt	NA	3.19E-05	7.50E-06	NA	NA	3.94E-05
Manganese	NA	1.44E-04	3.39E-05	NA	NA	1.78E-04
Mercury	NA	9.86E-05	2.32E-05	NA	NA	1.22E-04
Nickel	NA	7.97E-04	1.88E-04	NA	NA	9.84E-04
Selenium	NA	9.11E-06	2.14E-06	NA	NA	1.12E-05
HAP Totals	**21.6**	**0.7**	**0.2**	**0.006**	**0.004**	**22.5**

AP-42 Cooling Tower Emission Factor (Section 13.4, January 1995)

0.019	lb PM/1000 gal circulated
0.02%	% Liquid Drift
12,000	Total Dissolved Solids (mg/L)

Proposed Cooling Tower

Process Unit	Circulation Rate		Make-Up Rate		Total Dissolved Solids (mg/L)	$PM/PM_{10}/PM_{2.5}$				
						% Liquid Drift	EF	Unit	lb/hr[1]	tpy
Cooling Tower	192,000	gpm	0	gpm	5,000	0.0005%	1.98E-04	lb/1000 gal	2.280	9.986

Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emission Factor Calculation

$$PM/PM_{10}/PM_{2.5}\ EF = PM\,EF_{AP-42} * \frac{TLD_{design}}{TLD_{AP-42}} * \frac{TDS_{future}}{TDS_{AP-42}}$$

Where,

$PM\ EF_{AP-42}$ = AP-42 Emission Factor for PM10 (lb/1000 gal)

TLD_{design} = Design total liquid drift (%)

TLD_{AP-42} = Design total liquid drift (%)

TDS_{future} = Estimated future total dissolved solid content (mg/L)

TDS_{AP-42} = Total dissolved solid content used in AP-42 (mg/L)

Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emission Calculation

$$PM / PM_{10} / PM_{2.5} = (R + M) * PM\ EF$$

Where,

R = Recirculation rate (400 gal/min)

M = Make-up rate (20 gal/min - Assumed to be 3% of recirculation rate)

PAVED ROAD SPREADSHEET

Average Vehicle Weight **(W)** (tons):	3.00	Average weight of vehicles from Assumptions Tab
VMT	21,900	40 vehicles; 1.5 miles/day; 365 days per year
Potential Days of Operation	365	
Typical Days of Operation	365	
Road Surface Silt Loading (g/m^2):	0.6	Enter 0.6 for public road, 120 for apshalt batching industrial road, 12 for concrete batching industrial road, 70 for sand & gravel processing industrial road, 8.2 for quarry industrial road. If facility has a permit with a silt loading limit, use that s
Days/Year with at Least 0.01 inches of Precipitation	100	See Map - Figure 1 for value. 100 may be entered as a default value.

Determination of Annual Emissions

SOURCE OF EMISSION FACTOR:	EQUATION	VALUES
The emission factor is taken from Equation 1 in AP-42, 13.2.1, Paved Roads (updated January 2011).	**EF = [[(k) x [(*sL*)^0.91] x [(W)^1.02]]((1- (p/1460)) lb/VMT**	k = constant = 0.0022 for PM-10 and 0.00054 for PM-2.5 from AP-42 Table 13.2.1-1 (lb/VMT value) sL = road surface silt loading = 0.6 from AP-42 Table 13.2.1-3 or entered above W = Average Vehicle Weight (tons) p = Number of Days per Year

EMISSIONS CALCULATIONS

Process	Pollutant	Emission Factor	Emission Factor Units	Source of Emission Factor	Potential Emissions (tons/year)	Actual Emissions (Tons/Yr)	lbs/hour
Paved Road	**PM**	0.020	lb/vmt	AP-42	0.2162	0.2162	**0.04935**
	PM-10	0.004			0.0432	0.0432	**0.00987**
	PM-2.5	0.001			0.0106	0.0106	**0.00242**

SF6	No. of Components	SF6/ component, lbs	% leak Assumption	SF6, tons/year	GWP = 23,900
	10	100	0.5%	0.0025	59.75

		Uncontrolled			Controlled		
	Number of Components	Factor, lbs/hr/component	tons/yr CH4	tons/year CO2e	Factor, lbs/hr/component	tons/yr CH4	tons/year CO2e
Valves	500	0.008	17.52	367.92	0.00024	0.53	11.04
Flanges	1300	0.003	17.08	358.72	9E-05	0.51	10.76
Compressor seals	2	0.474	4.15	87.20	0.001422	0.01	0.26
Relief valves	30	0.216	28.38	596.03	0.000648	0.09	1.79
Open ended lines	20	0.031	2.72	57.03	9.3E-05	0.01	0.17
Total			69.85	1466.90		1.14	24.02

Emission factors from TCEQ vHP LDAR Program

		Horse Power	Number of Units	Operating Schedule				Total Time During 3-year Construction		Fuel Use		Emission Factors			Emissions, tons/project		missions, tons/ye		Unpaved Road Emissions			
				Hours/ day	Days/ week	Weeks/ yr	Capacity Factor (%)	Days (each)	Hours, total	gallons/h	gallons Total for 3-years	PM2.5, gr/HP-hr	NMOC/ NOx, gr/HP-hr	NOx, gr/HP-hr	PM2.5	NOx	PM2.5	NOx	Average Speed, mph	Miles per Project	PM2.5 Emissions, Tons/project	PM2.5 Emissions, Tons/year
Site preparation	Vibratory Compactor	180	2	10	5	20	0.75	100	1500	11.7	17550	0.22	3	3	0.065	0.893	0.022	0.298	5	7500	1.01	0.34
	Motor Grader	140	2	10	5	20	0.75	100	1500	9.2	13800	0.22	3	3	0.051	0.694	0.017	0.231	5	7500	1.01	0.34
	Dump Truck	400	2	10	5	10	0.75	50	750	26	19500	0.15	3	3	0.050	0.992	0.017	0.331	5	3750	0.51	0.17
	Wheel Loader	600	2	10	5	20	0.75	100	1500	42.5	63750	0.15	3	3	0.149	2.976	0.050	0.992	5	7500	1.01	0.34
	Dozer	350	2	10	5	8	0.75	40	600	24	14400	0.15	3	3	0.035	0.694	0.012	0.231	5	3000	0.41	0.14
	Excavator	350	4	10	5	25	0.75	125	3750	23.4	87750	0.15	3	3	0.217	4.340	0.072	1.447	5	18750	2.53	0.84
	Scraper	300	2	10	5	8	0.75	40	600	21.3	12780	0.15	3	3	0.030	0.595	0.010	0.198	5	3000	0.41	0.14
	Pavers	140	1	10	5	2	0.75	10	75	9.2	690	0.22	3	3	0.003	0.035	0.001	0.012	5	375	0.05	0.02
	Generators/Compressors	40	2	10	5	8	0.75	40	600	2.5	1500	0.44	5.6	5.6	0.012	0.148	0.004	0.049	NA	NA	NA	NA
Plant Construction	Welding Machine	40	10	10	5	50	0.50	250	12500	3.2	40000	0.6	5.6	5.6	0.331	3.086	0.110	1.029	NA	NA	NA	NA
	Dump Truck	400	2	10	5	20	0.50	100	1000	26	26000	0.15	3	3	0.066	1.323	0.022	0.441	5	5000	0.68	0.23
	Wheel Loader	600	2	10	5	50	0.50	250	2500	10.2	25500	0.22	3	3	0.364	4.960	0.121	1.653	5	12500	1.69	0.56
	Water Truck	150	2	10	5	120	0.25	600	3000	42.5	127500	0.15	3	3	0.074	1.488	0.025	0.496	5	15000	2.03	0.68
	Crawler Crane	300	2	10	5	50	0.50	250	2500	20.3	50750	0.15	3	3	0.124	2.480	0.041	0.827	NA	NA	NA	NA
	Concrete Truck	300	2	10	5	8	0.50	40	400	20.7	8280	0.15	3	3	0.020	0.397	0.007	0.132	5	2000	0.27	0.09
	Concrete Pump	70	2	10	5	8	0.50	40	400	6.1	2440	0.3	3.5	3.5	0.009	0.108	0.003	0.036	NA	NA	NA	NA
	Flat Bed Tracktor Trailor	250	2	10	5	10	0.50	50	500	22.7	11350	0.15	3	3	0.021	0.413	0.007	0.138	5	2500	0.34	0.11
	Forklift	80	5	10	5	80	0.50	400	10000	5.42	54200	0.3	3.5	3.5	0.265	3.086	0.088	1.029	5	50000	6.75	2.25
	Crane	300	2	10	5	35	0.50	175	1750	18.92	33110	0.15	3	3	0.087	1.736	0.029	0.579	NA	NA	NA	NA
	Generators/Compressors	40	6	10	5	80	0.50	400	12000	2.51	30120	0.44	5.6	5.6	0.233	2.963	0.078	0.988	NA	NA	NA	NA
													Totals		2.2	33.4	0.7	11.1		138,375	18.7	6.2

All Engines are assumed to use diesel fuel

PM2.5 emission factor for unpaved roads based on AP-42, Chapter 13-2-2 equation, vehicle weight = 22 tons; silt content = 8.5%; a=0.9; b=0.45 ; k=0.15. Factor = 0.27 lbs/VMT

	Tons/Year	
	PM2.5	Nox
Engine Emissions from Construction	0.73	11.1
Unpaved Roadway Emissions	6.23	
Total	6.96	11.1

Air Quality Analysis

Indianapolis Power & Light Company

Eagle Valley Generating Plant

Martinsville, Indiana (Morgan County)

Tracking and Plant ID: T109-32471-00004

Proposed Project

Indianapolis Power & Light (IPL) Company has submitted a request for a significant major source modification of their Eagle Valley Generating Station near Martinsville, Indiana with an increase in carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). The increase in CO, NO_2, PM_{10}, and $PM_{2.5}$ emissions will be as a result of the installation of two natural gas fired combined cycle combustion turbines and an auxiliary boiler at the IPL Eagle Valley Generating Station in Martinsville, Indiana. Additional criteria pollutant emissions will be the result of new cooling towers, a dew point heater, an emergency generator, and an emergency fire pump.

Environmental Resources Management (ERM) in Rolling Meadows, Illinois prepared the air quality analysis portion of the Prevention of Significant Deterioration (PSD) permit application for IPL. The Modeling Section in the Office of Air Quality (QAQ) received the air quality analysis portion of the permit application on November 7, 2012 and the air quality modeling files on November 26, 2012. A revised permit application was received on July 9, 2013 with the revised modeling files received on July 15, 2013. This technical support document provides the air quality analysis review of the PSD permit application.

Analysis Summary

Based on the potential emissions after controls, a PSD air quality analysis was triggered for CO, NO_2, PM_{10}, and $PM_{2.5}$. The significant impact analysis determined modeling concentrations for NO_2, PM_{10}, and $PM_{2.5}$ exceeded the significant impact levels. A refined analysis, PSD increment analysis and National Ambient Air Quality Standards (NAAQS) analysis were required. The pre-construction monitoring requirement was triggered for the 24-hour PM_{10} and 24-hour $PM_{2.5}$ as a result of this analysis. An additional impact analysis was conducted and showed no significant impacts. Based on the modeling results, the proposed PSD major source modification will not have a significant impact upon federal air quality standards.

Air Quality Impact Objectives

The purpose of the air quality impact analysis in the permit application is to accomplish the following objectives. Each objective is individually addressed in this document in each section outlined below.

A. Establish which pollutants require an air quality analysis based on PSD significant emission rates.

B. Provide analyses of actual stack heights with respect to Good Engineering Practice (GEP), the meteorological data used, a description of the model used in the analysis, and the receptor grid used for the analyses.

C. Determine the significant impact levels, the area impacted by the source's emissions and background air quality levels.

D. Demonstrate that the source will not cause or contribute to a violation of the NAAQS or PSD increment if the applicant exceeds significant impact levels.

E. Perform a qualitative analysis of the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park located in south central Kentucky about 150 kilometers south of Louisville.

F. Secondary Ozone Formation Analysis

G. Secondary $PM_{2.5}$ Formation Analysis

H. Summary of Air Quality Analysis

Section A - Pollutants Analyzed for Air Quality Impact

Applicability

The PSD requirements, 326 IAC 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1 and in the Code of Federal Regulations (CFR) 52.21(b) (23) (i). Morgan County is classified as attainment for all criteria pollutants. Morgan County was classified as nonattainment for the annual $PM_{2.5}$ standard, but the United States Environmental Protection Agency (U.S. EPA) approved the Indiana Department of Environmental Management (IDEM) request to redesignate Morgan County to attainment for the annual $PM_{2.5}$ standard effective July 11, 2013, Federal Register Volume 78, No. 133 dated July 11, 2013.

Proposed Project Emissions

CO, NO_2, PM_{10}, $PM_{2.5}$, SO_2, VOCs, and H_2SO_4 are the pollutants which will be emitted from the IPL Eagle Valley PSD major source modification. An air quality analysis is required for CO, NO_2, PM_{10} and $PM_{2.5}$ pollutants because potential emissions after controls exceed the significant emission rates (SER) as shown in Table 1. Sulfuric Acid Mist (SAM) will exceed the significant emission rate for PSD applicability. However, no air quality analysis is required for SAM under the PSD regulations and SAM has no monitoring concentration threshold listed in 326 IAC 2-2-4. The significant emission rates in Table 1 were taken from Table 4-2 of the IPL Eagle Valley PSD permit application technical support document for NO_2, SO_2, SAM, and VOCs and the modeled emission limits in the case of CO, $PM_{2.5}$, and PM_{10}. The modeled emissions limits for CO, $PM_{2.5}$, and PM_{10} listed in Table 1 on page 3 are somewhat higher than the emissions listed in Table 4-2 of the PSD permit application. Three operating scenarios were modeled by ERM to determine the highest modeled impact, or worst case operating scenario, for each criteria pollutant with the exception of PM_{10} and $PM_{2.5}$ where only two operating scenarios were applicable to particulate matter.

Table 1
Significant Emission Rates for PSD Applicability

CRITERIA POLLUTANT	POTENTIAL EMISSION RATE (Source Totals)	SIGNIFICANT EMISSION RATE	PRELIMINARY AIR QUALITY ANALYSIS REQUIRED
	(tons/year)	(tons/year)	
CO	670	100	Yes
NO_2	176.7	40	Yes
PM_{10}	183	15	Yes
$PM_{2.5}$	149.5	10	Yes
SO_2	30.9	40	No
VOC	170	40	Yes
H_2SO_4 (Sulfuric Acid Mist)	13.5	7	No

Section B – Good Engineering Practice (GEP), Met Data, Model Used, Receptor Grid

Stack Height Compliance with Good Engineering Practice (GEP)

Applicability

Stacks should comply with GEP requirements established in 326 IAC 1-7-4. If stacks are lower than GEP, excessive ambient concentrations due to aerodynamic downwash may occur. Dispersion modeling credit for stacks taller than 65 meters or 213 feet is limited to GEP for the purpose of establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which would affect the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. A GEP stack height is determined for each nearby structure by the following formula:

$$Hg = H + 1.5L$$

Where: Hg is the GEP stack height
H is the structure height
L is the structure's lesser dimension (height or width)

Existing Stack

Since the existing stack heights of the units for which the modification is proposed are below GEP stack height, the effect of aerodynamic downwash will be accounted for in the air quality analysis for the project.

Meteorological Data

The meteorological data used in the American Meteorological Society Environmental Protection Agency Regulatory Model (AERMOD) consisted of 2006 through 2010 surface meteorological data from the Indianapolis, Indiana National Weather Service (NWS) station merged with the upper air data from the Lincoln, Illinois NWS upper air station. Additionally, the Indianapolis 1-minute Automated Surface Observing System (ASOS) wind speed and wind direction data were processed with the AERMINUTE preprocessor version 11325. The meteorological data were preprocessed into an AERMOD ready format by the OAQ using U.S.EPA's AERMET, Version 12345, meteorological preprocessor for AERMOD.

Model Description

ERM and OAQ used the most recent version of AERMOD, Version 12345, at the time the permit application was submitted to determine maximum off-property concentrations or impacts for each criteria pollutant. All regulatory default options were utilized in the U.S. EPA approved model, as listed in the 40 Code of Federal Regulations Part 51, Appendix W "Revision to the Guideline on Air Quality Models".

The Auer Land Use Classification Scheme was used to determine the land use in the area. The area is considered primarily rural; therefore, a rural classification was used.

Receptor Grid

The receptor grids extended to a distance approximately 50 kilometers from the plant. Fence line receptors were closely spaced at 50 to 100 meters along the plant fence line and spaced every 100 meters out to a distance of 1000 meters from the plant property lines to identify the influence of aerodynamic building downwash. A total of 7237 receptors were used in the significant impact area air quality analysis for CO, NO_2, PM_{10}, and $PM_{2.5}$ with a more refined receptor grid of 4621 receptors for the NO_2 NAAQS and PSD increment analyses and 2461 receptors for the PM_{10} and the $PM_{2.5}$ NAAQS analyses. A total of 7237 receptors were used for the $PM_{2.5}$ PSD increment analysis which was essentially the SIL analysis for $PM_{2.5}$ and 4621 receptors for the PM_{10} PSD increment analysis. Each receptor grid was sufficiently large enough to extend to a distance beyond the significant impact area for the respective pollutant.

Section C - Significant Impact Level/Area (SIA) and Background Air Quality Levels

A significant impact analysis was conducted to determine if the source exceeded the PSD significant impact levels (SILs) or concentrations. If the source's concentrations exceed the SILs, further air quality analyses are required. Refined modeling for the 1-hour and 8-hour CO and the PM_{10} annual time averaging periods were not required because the results did not exceed the SILs. SILs are defined by the following time periods shown in Table 2 on page 5 with all the maximum-modeled concentrations from the worst case operating scenarios. Case 2 operating scenario had the highest modeled impact on the air quality for the 1-hour and annual NO_2 and the 24-hour and annual PM_{10} and $PM_{2.5}$. Case 3 operating scenario resulted in the highest modeled concentrations for the 1-hour and 8-hour CO. The 1-hour NO_2

SIL shown in Table 2 is the highest 5 year average of the 1-hour maximum daily concentrations for each receptor modeled. Likewise, the 24-hour $PM_{2.5}$ SIL is the highest 5 year average of the maximum 24-hour concentrations for each receptor. Additionally, the annual $PM_{2.5}$ SIL is the highest 5 year average of the annual concentrations at each receptor. The 1-hour and annual NO_2 modeled results shown in Table 2 were adjusted by the default ambient ratio for the nitrous oxides (NO_x) to NO_2 conversion, which is a 0.8 default ambient ratio for the 1-hour concentration and is a 0.75 default ambient ratio for the annual concentration. This is known as the Tier 2 or the Ambient Ratio Method (ARM) modeling approach for NO_2.

The 24-hour and annual $PM_{2.5}$ SILs were vacated and remanded by the United States Court of Appeals for the District of Columbia Circuit Court decision on January 22, 2013. U.S. EPA has interpreted the Court's decision for pending PSD permits to not rely solely on the $PM_{2.5}$ SILs to demonstrate that a source will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS or PSD increments. In the case of IPL Eagle Valley, the annual and 24-hour $PM_{2.5}$ modeling results were above the $PM_{2.5}$ SILs and below the $PM_{2.5}$ NAAQS so the use of the $PM_{2.5}$ SILs does not impact the modeling results for the IPL Eagle Valley PSD major source modification.

Table 2
Significant Impact Analysis

CRITERIA POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACT (ug/m^3)	SIGNIFICANT IMPACT LEVEL (ug/m^3)	REFINED AQ ANALYSIS REQUIRED
CO	1-Hour	286.6	2000	No
CO	8-Hour	111.5	500	No
NO_2	1-Hour	68.9	7.5	Yes
NO_2	Annual	1.4	1	Yes
PM_{10}	24-Hour	12.1	5	Yes
PM_{10}	Annual	0.53	1	No
$PM_{2.5}$	24-Hour	6.0	1.2	Yes
$PM_{2.5}$	Annual	0.32	0.3	Yes

Preconstruction Monitoring Analysis

Applicability

The PSD requirements, 326 IAC 2-2-4, require an air quality analysis of the new source or the major PSD modification to determine if the preconstruction monitoring threshold is triggered. In most cases, post construction monitoring can satisfy this requirement if the preconstruction monitoring threshold has been exceeded. In the case of the significant monitoring concentration (SMC) for $PM_{2.5}$, the January 22, 2013 decision by the Circuit Court vacated the use of the 24-hour $PM_{2.5}$ SMC to exempt a source from the preconstruction monitoring data requirement. However, in most cases existing ambient $PM_{2.5}$ monitoring data can be used to meet the preconstruction requirement, as was done here for the IPL Eagle Valley

PSD major source modification.

Modeling Results

A comparison of the preliminary modeling results was compared to the PSD preconstruction monitoring thresholds. The criteria pollutants, PM_{10} and $PM_{2.5}$, did trigger the preconstruction monitoring requirement. As a result, the preconstruction monitoring requirement for PM_{10} and $PM_{2.5}$ is necessary for this PSD major source modification, but the preconstruction monitoring requirement is met by using existing air quality monitoring data for PM_{10} and $PM_{2.5}$. The modeling results for the preconstruction monitoring requirement are listed in Table 3 on page 6.

Background Concentrations

Applicability

EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA-450/4-87-007) Section 2.4.1 is cited for approval of the air quality monitoring sites for this area. Background air quality monitoring concentrations for NO_2, PM_{10}, and $PM_{2.5}$ are required as part of this analysis since the modeling results were above the SILs for NO_2, PM_{10} and $PM_{2.5}$ and a subsequent NAAQS analysis was required. As a result, these analyses were completed for NO_2, PM_{10} and $PM_{2.5}$ PSD increments and NAAQS.

Table 3
Preconstruction Monitoring Analysis

CRITERIA POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACT (ug/m^3)	DE MINIMIS MONITORING LEVEL (ug/m^3)	ABOVE DE MINIMIS MONITORING LEVEL
CO	8-Hour	111.5	575	No
NO_2	Annual	1.4	14	No
PM_{10}	24-Hour	12.1	10	Yes
$PM_{2.5}$	24-Hour	6.0	4	Yes

Background Monitors

Background data were taken from the air quality monitoring sites in the Bloomington and Evansville areas using the NO_2 and PM_{10} monitors located on Buena Vista Road in Evansville and the Bloomington-Binford $PM_{2.5}$ monitor located on East 2nd Street in Bloomington. The 1-hour NO_2 background concentration used the 98th percentile or the 8th high averaged over 3 years and the annual NO_2 background used the 3-year average of the highest annual concentrations. The maximum 2nd high concentrations were used for the 24-hour PM_{10}. The 24-hour $PM_{2.5}$ background concentration used the 24-hour 3-year design value or the 98th percentile of the 24-hour value averaged over 3 years. The annual $PM_{2.5}$ background concentration used the annual 3-year design value. The NO_2, PM_{10}, and $PM_{2.5}$ background concentrations were taken from the 2010 to 2012 air quality monitoring data.

Table 4
Existing Monitoring Data Used for Background Concentrations

CRITERIA POLLUTANT	MONITOR SITE	MONITOR LOCATION	AVERAGING PERIOD	CONCENTRATION (ug/m^3)
NO_2	18-163-0021	Evansville	1-Hour	67.9
NO_2	18-163-0021	Evansville	Annual	20.9
$PM_{2.5}$	18-105-0003	Bloomington	24-Hour	23
$PM_{2.5}$	18-105-0003	Bloomington	Annual	10.4
PM_{10}	18-163-0021	Evansville	24-Hour	34.7

Section D - NAAQS and PSD Increment

NAAQS Compliance Analysis and Results

NAAQS air quality modeling for the annual time averaging period for PM_{10} and the 1-hour and 8-hour CO time averaging periods were not required since the IPL Eagle Valley PSD major source modification air quality analysis was below the SILs for the annual PM_{10} of 1 ug/m^3 and the 1-hour and 8-hour CO SILs of 2000 ug/m^3 and 500 ug/m^3, respectively. The OAQ NAAQS modeling results are shown in Table 5. All maximum modeled concentrations were compared to their respective NAAQS. All maximum modeled concentrations during the five years of modeling were below the NAAQS standards with the exception of the 1-hour NO_2 NAAQS. Additional air quality modeling was not required for the 24-hour PM_{10} and $PM_{2.5}$ and the annual $PM_{2.5}$ and NO_2 standards. The 1-hour NO_2 NAAQS modeling results shown in Table 5 had a violation of the 1-hour NO_2 standard of 100 parts per billion (ppb) or 188.7 ug/m^3. The highest 8th-high 1-hour NO_2 concentration averaged across five years was 419.7 ug/m^3 resulting in a total 1-hour NO_2 concentration of 487.6 ug/m^3 with a background concentration of 67.9 ug/m^3. The highest 8th-high maximum daily 1-hour NO_2 modeled concentration of 419.7 in Table 5 was adjusted from an actual modeled concentration of 524.6 ug/m^3 by using the NO_2/NO_x default ambient ratio of 0.8 (524.6 X 0.8 = 419.7) for a 1-hour concentration. The annual NO_2 modeled concentration shown in Table 5 has been adjusted by the 0.75 default ambient ratio for NO_x to NO_2 conversion for an annual concentration.

The 24-hour $PM_{2.5}$ NAAQS analysis shown in Table 5 used the 98th percentile or the 8th highest 24-hour concentration averaged across five years of modeling for the modeled concentration which is the same form of the 24-hour $PM_{2.5}$ standard as the 24-hour $PM_{2.5}$ monitored background concentration. This change to the 98th percentile form of the 24-hour $PM_{2.5}$ standard for the NAAQS analysis is the result of the recommendation from the “Draft Guidance for $PM_{2.5}$ Permit Modeling” document dated March 4, 2013. Additionally, the annual $PM_{2.5}$ NAAQS was revised from 15 ug/m^3 to 12 ug/m^3 by the U.S. EPA on December 14, 2012 with the final rule effective date of March 18, 2013, Federal Register dated January 15, 2013. The annual $PM_{2.5}$ NAAQS shown in Table 5 reflects this revision in the annual $PM_{2.5}$ standard to 12 ug/m^3.

Table 5
NAAQS Analysis

CRITERIA POLLUTANT	TIME AVERAGING PERIOD	YEAR	MODELED CONCENTRATION (ug/m^3)	BACKGROUND CONCENTRATION (ug/m^3)	TOTAL CONCENTRATION (ug/m^3)	NAAQS (ug/m^3)	NAAQS VIOLATION
NO_2	1-Hour	5 Year	419.7	67.9	487.6	188.7	Yes
NO_2	Annual	2007	6.9	20.9	27.8	100	No
$PM_{2.5}$	24-Hour	5 Year	3.3	23	26.3	35	No
$PM_{2.5}$	Annual	5 Year	0.5	10.4	10.9	12	No
PM_{10}	24-Hour	2008	6.2	34.7	40.9	150	No

1-Hour NO_2 Contribution Analysis and Results

The 8th-high 1-hour NO_2 concentration represents the 98th percentile of the 1-hour daily maximum concentrations averaged across five years of modeling. A total of 27 receptors violated the 1-hour NO_2 NAAQS of 100 ppb or 188.7 ug/m^3. As a result, OAQ performed additional 1-hour NO_2 modeling for the 27 receptors which violated the 1-hour NO_2 NAAQS to determine if the impact from the IPL Eagle Valley PSD major source modification had a significant contribution to any violating receptor. For this additional

modeling analysis, the maximum daily contribution output option was selected in AERMOD and the 1-hour NO_2 SIL of 7.5 ug/m^3 was used as the threshold value for a significant contribution. For the highest 8th-high maximum daily 1-hour NO_2 concentration averaged over five years in Table 5, the total contribution by the IPL PSD major source modification was 0.00175 ug/m^3. The results of the 1-hour NO_2 contribution analysis for the highest 1-hour concentration for a NAAQS violating receptor are shown in Table 6. All 27 violating receptors had 1-hour NO_2 contributions from the IPL PSD major source modification which were below the 1-hour NO_2 SIL of 7.5 ug/m^3. As a result, the IPL PSD major source modification does not have a significant contribution or impact on any receptor which showed a 1-hour NO_2 NAAQS violation.

Table 6
1-Hour NO_2 Contribution Analysis

CRITERIA POLLUTANT	TIME AVERAGING PERIOD	YEAR	MODELED CONCENTRATION (ug/m^3)	BACKGROUND CONCENTRATION (ug/m^3)	ABOVE NAAQS > 188.7	TOTAL CONTRIBUTION IPL PSD (ug/m^3)	SIL (ug/m^3)	ABOVE SIL
NO_2	1-Hour	5 Year	419.7	67.9	Yes	0.00175	7.5	No

The OAQ performed an additional air quality modeling analysis for all receptors in the 1-hour NO_2 SIA analysis, a total of 2535 receptors, which exceeded the 1-hour NO_2 SIL of 7.5 ug/m^3 to determine if any of these receptors exceeded the 1-hour NO_2 NAAQS. A total of four receptors did exceed the 1-hour NO_2 NAAQS when the background concentration of 67.9 ug/m^3 was added to the modeled concentration. However, the 8th-high (98th percentile) of the maximum daily 1-hour NO_2 contribution averaged over 5 years from the IPL Eagle Valley PSD major source modification at each of the four receptors was below the SIL of 7.5 ug/m^3. The results of the 1-hour NO_2 contribution modeling for each of the four receptors are shown in Table 7.

Table 7
1-Hour NO_2 Contribution Analysis for Receptors Exceeding SIL and NAAQS

CRITERIA POLLUTANT	TIME AVERAGING PERIOD	YEAR	MODELED CONCENTRATION (ug/m^3)	BACKGROUND CONCENTRATION (ug/m^3)	ABOVE NAAQS > 188.7	TOTAL CONTRIBUTION IPL PSD (ug/m^3)	SIL (ug/m^3)	ABOVE SIL
NO_2	1-Hour	5 Year	204.3	67.9	Yes	0.00582	7.5	No
NO_2	1-Hour	5 Year	138.4	67.9	Yes	0.00555	7.5	No
NO_2	1-Hour	5 Year	132.4	67.9	Yes	0.00149	7.5	No
NO_2	1-Hour	5 Year	131.2	67.9	Yes	0.01989	7.5	No

Analysis and Results of Source Impact on the PSD Increment

Applicability

Maximum allowable increases or PSD increments are established by 326 IAC 2-2 for PM_{10}, $PM_{2.5}$, and NO_2. This rule also limits a source to no more than 80 percent of the available PSD increment to allow for future growth. Only $PM_{2.5}$ emissions increases since the $PM_{2.5}$ major source baseline date of October 20,

2010 actually consume $PM_{2.5}$ increment. The IPL Eagle Valley PSD major source modification will establish the $PM_{2.5}$ minor source baseline date for Morgan County. The $PM_{2.5}$ minor source baseline date for Morgan County will be the date of the IPL Eagle Valley permit application.

Source Impact

Since the modeled impacts for the annual NO_2 and $PM_{2.5}$, and 24-hour PM_{10} and $PM_{2.5}$ from the IPL Eagle Valley major source modification were above the SILs of 5 ug/m^3 (24-hour PM_{10}), 1.2 ug/m^3 (24-hour $PM_{2.5}$), 1 ug/m^3 (annual NO_2), and 0.3 ug/m^3 (annual $PM_{2.5}$) a PSD increment analysis for the existing major sources was required as part of this air quality analysis. The results of the OAQ NO_2, PM_{10}, and $PM_{2.5}$ PSD increment analysis are shown below in Table 8. The annual NO_2 modeled concentration shown in Table 8 has been adjusted by the 0.75 default ambient ratio for NO_x to NO_2 conversion for an annual concentration.

Table 8
PSD Increment Analysis

CRITERIA POLLUTANT	TIME AVERAGING PERIOD	YEAR	MODELED CONCENTRATION (ug/m^3)	PSD INCREMENT (ug/m^3)	80 PERCENT OF PSD INCREMENT (ug/m^3)	PSD INCREMENT VIOLATION
NO_2	Annual	2007	1.75	25	20	No
$PM_{2.5}$	24-Hour	2008	4.9	9	7.2	No
$PM_{2.5}$	Annual	2007	0.39	4	3.2	No
PM_{10}	24-Hour	2008	6.2	30	24	No

The results of the modeling show no PSD increment for NO_2, PM_{10}, and $PM_{2.5}$ or 80 percent of any PSD increment will be violated as a result of this PSD major source modification at the IPL Eagle Valley facility.

Part E – Qualitative Analysis

Additional Impact Analysis

All PSD permit applicants must prepare additional impacts analysis for each pollutant subject to regulation under the Clean Air Act. This analysis assesses the impacts on economic growth, soils and vegetation, wildlife and plant species, and visibility caused by any increase in emissions of any regulated pollutant from the source. The IPL Eagle Valley PSD permit application provided an additional impact analysis performed by ERM.

Economic Growth

No impact from the economic growth is expected from the IPL Eagle Valley PSD permit major source modification and physical changes at the IPL Eagle Valley facility. The existing Martinsville, Indiana and Morgan County community will be able to adequately handle potential commercial growth associated with this future plant modification. An additional employment of 30 to 40 people is expected as a result of this facility modification.

Soils and Vegetation Analysis

A soils and vegetation analysis was performed by ERM to assess the impact of the criteria pollutant air emissions. Soil types in Morgan County include silt loam, clay loam, and sandy loam soils. Crops in Morgan County consist mainly of corn, soybeans, and wheat. Trees in Morgan County are mostly hardwoods such as maples and oaks. The results of the soils and vegetation analysis show the modeled impacts are well below the thresholds necessary to have an adverse impact on the surrounding soils and vegetation. The results of the soils and vegetation analysis are listed in the IPL Eagle Valley PSD Permit Application, section 8, page 26.

Federal Endangered Species Analysis

Federal and State endangered or threatened species are listed by the Indiana Department of Natural Resources; Division of Nature Preserves for Morgan County, Indiana and includes eight species of mussels, six species of birds, three species of reptiles, two species of bats, and one specie each of fish and amphibian. The mussels and birds listed are commonly found along major rivers and lakes while the bats are found near caves. The Martinsville Eagle Valley facility is not expected to have any additional adverse effects on the habitats of the endangered species other than that which has already occurred from the industrial and residential activities in the area. The endangered species of bats maintains habitats in caves and mines none of which are near the Martinsville facility. Federal and State endangered or threatened plants are listed by the Indiana Department of Natural Resources, Division of Nature Preserves and include no threatened or endangered species of plants in the Morgan County area of central Indiana.

Visibility Analysis

The VISCREEN model is designed as a screening model to determine the visual impact parameters from a single source plume. It is used basically to determine whether or not a plume is visible as an object itself.

The NO_2 and PM_{10} emission limits were used to run a local visibility Level 1 analysis. VISCREEN Version 1.01 was used to determine if the color difference parameter (Delta-E) or the plume (green) contrast limits were exceeded. The Delta-E was developed to specify the perceived magnitude of color and brightness changes and is used as the primary basis for determining the perceptibility of plume visual impacts. The plume constant can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object and its background. This is used to determine how the human eye responds differently to different wavelengths of light. A Delta-E of 1.483 and a plume contrast of 0.016 were the maximum visual impacts at Interstate I-70 which is within the study area. The Delta-E and plume contrast values located at Interstate I-70 are below the threshold values for the Delta-E of 2.0 and for the plume contrast of 0.05.

The nearest Class I area is Mammoth Cave National Park in Kentucky approximately 300 kilometers from the IPL Eagle Valley facility in Martinsville, Indiana. A screening visibility was conducted by ERM which showed no visibility analysis is required on the Class I area since the Q/D ratio, where Q is the total emissions of NO_2, PM_{10}, SO_2, and H_2SO_4 (sulfuric acid mist) in tons per year and D is the distance in kilometers, resulted in a value of 1.5 which is below the threshold value of 10 required to perform the visibility analysis on a Class I area.

Additional Impact Analysis Conclusions

Finally, the results of the additional impact analysis conclude the operation of the IPL Eagle Valley facility will have no significant impact on economic growth, soils, vegetation, endangered or threatened species, and visibility in the immediate vicinity or on any Class I area. Since the modeled impacts do not extend

beyond the immediate area just beyond the plant property, no adverse impacts are expected from the modification at the IPL Eagle Valley facility in Martinsville, Indiana. Additionally, there are no threatened or endangered plant species in Morgan County.

Part F - Secondary Ozone Formation Analysis

Because of the well established relationship between nitrogen oxides (NO_x), volatile organic compounds (VOCs), and the regional transport formation of ozone, U.S. EPA recently finalized the Cross State Air Pollution Rule (CSAPR) to assist states to meet the ozone NAAQS. This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the ozone NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs). While the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating CSAPR on August 21, 2012, the modeling analysis conducted by U.S. EPA is considered valid and will be used for the ozone analysis.

U.S. EPA used a regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all ozone monitors in the eastern U.S. and emission reduction levels necessary to achieve those results. To examine the possible impact of IPL Eagle Valley, results from the modeling U.S. EPA conducted to establish the 2012 and 2014 base case emissions in CSAPR were used for this analysis. The CSAPR website is located at http://www.epa.gov/crossstaterule/techinfo.html.

Information regarding the NO_x emissions modeled for CSAPR can be found in the "EmissionsSummaries.xlsx" spreadsheet under the Emissions Inventory Final Rule TSD section at EPA's CSAPR website for technical information http://www.epa.gov/crossstaterule/techinfo.html. The spreadsheet shows the base case annual NO_x emissions for Indiana in 2012 at 455,325 tons and base case annual NO_x emissions by 2014 at 431,342 tons. Indiana's total NO_x emission reduction between these scenarios totals 23,983 tons. All surrounding states make similar significant reductions. IPL Eagle Valley's proposed emissions would be 176.7 tons per year of NO_x and 170.0 tons per year of VOCs for a total of 346.7 tons per year of NO_x and VOCs.

8-Hour Ozone Modeling Results

The nearest ozone monitor to IPL Eagle Valley is the Monrovia ozone monitor in Morgan County. The current design value for 2010-2012 is 69 parts per billion (ppb), below the 8-hour NAAQS of 75 ppb. The U.S. EPA CSAPR results show the maximum modeled 8-hour ozone concentration for Morgan County is 71.7 ppb for the 2012 base case and 70.2 ppb for the 2014 base case. This is a decrease of 1.5 ppb as a result of NO_x emission adjustments between 2012 and 2014 base case emission calculations, based on emission growth factors. In order for this modeled 8-hour ozone concentration reduction to occur, Indiana's 2014 NO_x emissions were reduced from the 2012 base case emissions by 23,983 tons. The Morgan County monitoring site is not necessarily impacted by every EGU in Indiana, but in the surrounding states, thousands of tons of annual NO_x emission reductions are projected to occur by 2014, many of which would impact this site. Therefore, to estimate the impact of IPL Eagle Valley on modeled concentrations, the ratio of IPL Eagle Valley's NO_x and VOC emissions to Indiana's 2012 to 2014 base case NO_x emission reduction was calculated. This ratio was then compared to the modeled ozone impact from the difference between the CSAPR 2012 and 2014 base case modeling results.

1) **346.7 tons** IPL Eagle Valley NO_x and VOC emissions / **23,983 tons** of Indiana's NO_x base case emissions reduced from 2012 to 2014 = **1.45%** ratio of IPL Eagle Valley's NO_x and VOC emissions compared to Indiana's NO_x emissions

2) **1.45%** IPL Eagle Valley emission ratio * **1.5 ppb** maximum 8-hour 2012 to 2014 Base Case modeled results for Morgan County = **0.022 ppb** of IPL Eagle Valley 8-hour ozone impact

3) **0.022 ppb** of IPL Eagle Valley 8-hour ozone impact / **70.2 ppb** at Morgan County ozone monitor from 2014 base case maximum modeled results = **0.03%** IPL Eagle Valley's impact on the 2014 base case modeled concentration.

Tables are located in CSAPR_AQModeling.pdf, Appendix B, pages B-10 and B-12, for 8-hour ozone design values that show the base case 2012 ozone concentrations at surrounding monitoring sites versus projected base case 2014 ozone concentrations. 2012 Base Case represents modeled results taken from the 2012 and 2014 Base Case emissions, which represents the 2014 Base emissions with emission adjustments from growth factors included in the modeling. Table 9 below shows the CSAPR modeling results for the Morgan County and nearby monitors and the potential impacts from IPL Eagle Valley.

Table 9
EPA's Cross-State Air Pollution Rule - 8-Hour Ozone Modeling Results

Monitor ID	County	2012 Base (ppb)	2014 Base (ppb)	2012 - 2014 Base (ppb)	Anticipated Source Impact (ppb)	Source Impact on 2014 Base Results (%)
181090005	Morgan	71.7	70.2	1.5	0.022	0.031%
180630004	Hendricks	68.9	67.4	1.5	0.022	0.032%
180810002	Johnson	70.7	69.3	1.4	0.020	0.029%
180970057	Marion	70.9	69.6	1.3	0.019	0.027%

Summary of Ozone Results

IPL Eagle Valley's NO_x and VOC emissions were compared with the U.S. EPA CSAPR modeling for 8-hour ozone to determine what impacts may occur as a result of ozone formation. When IPL Eagle Valley emissions were compared with the amount of NO_x emission reductions realized from emission estimates associated with base case emissions for CSAPR and compared with CSAPR modeling results for 8-hour ozone, the impacts from IPL Eagle Valley on the Morgan County ozone monitor are anticipated to be minimal and not have a significant impact on the attainment status of Morgan County and any surrounding counties.

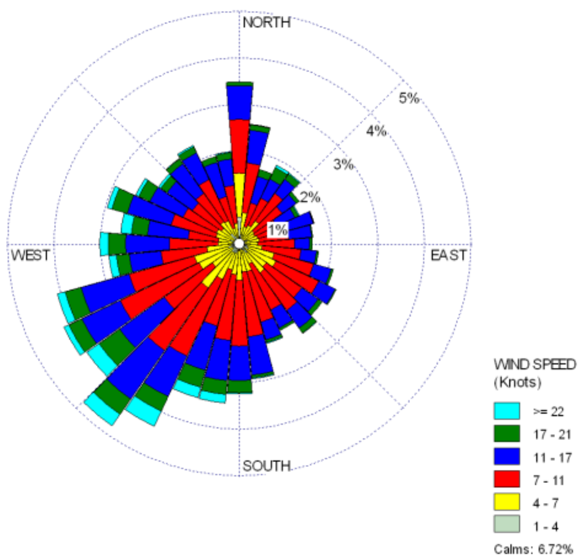
Part G - Secondary $PM_{2.5}$ Formation Analysis

In addition to direct emissions of $PM_{2.5}$; other pollutants, chiefly NO_x and SO_2, can lead to formation of $PM_{2.5}$ further downwind. The photochemical reactions that transform these pollutants into particulate nitrates and sulfates, which become the major species of $PM_{2.5}$, take place over hours or days. Dispersion modeling for the NO_2 primary pollutant shows the concentrations are well below the respective NAAQS for the IPL Eagle Valley contribution and will further diminish within the modeling domain of 50 km. Since the 1-hour NO_2 standard is very restrictive, these levels would likely prevent the pollutants from impacting secondary formation significantly enough to result in a violation of the $PM_{2.5}$ standards. SO_2 dispersion modeling was not required for this PSD major source permit modification since the SER was below 40 tons per year.

It is possible that some transformation into nitrates and sulfates from this source may occur and be transported downwind. No peer-reviewed regulatory model presently exists to examine the photochemical impacts of an individual source of SO_2 and NO_x. All photochemical models are regional scale and a source of this size would not show any measurable impact. Therefore, other available information from emissions inventories, meteorological analyses, and other modeling projects can be used to estimate the impact from this source.

The nearest active $PM_{2.5}$ monitor to IPL Eagle Valley is the West 18th Street $PM_{2.5}$ monitor in western Marion County. The 2011 wind rose taken from the Indianapolis International Airport in Indianapolis, Marion County shows the winds typically blow from the southwest and west. IPL Eagle Valley would be considered upwind of the West 18th Street monitor.

Indianapolis 2011



The 2009 – 2012 annual $PM_{2.5}$ design value at the West 18th Street monitor in Marion County is 12.7 µg/m^3, which is just above the annual $PM_{2.5}$ NAAQS of 12.0 µg/m^3. The 2009 – 2012 24-hour $PM_{2.5}$ design value at the West 18th Street monitor in Marion County is 29.0 µg/m^3, below the 24-hour $PM_{2.5}$ NAAQS of 35.0 µg/m^3.

<u>Secondary $PM_{2.5}$ Weight of Evidence Analysis based on EPA's CSAPR Modeling</u>

Because of the well established relationship between NO_x and SO_2, and the regional transport and formation of $PM_{2.5}$, U.S. EPA recently finalized the Cross State Air Pollution Rule (CSAPR) to assist states to meet the $PM_{2.5}$ NAAQS. This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the $PM_{2.5}$ NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs). While the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating CSAPR on August 21, 2012, the modeling analysis conducted by U.S. EPA is considered valid and will be used for the secondary $PM_{2.5}$ analysis. U.S. EPA used a regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all $PM_{2.5}$ monitoring sites in the eastern U.S. and emission reduction levels necessary to achieve those results. To examine the possible impact of IPL Eagle Valley, results from the modeling U.S. EPA conducted to establish the final 2014 budgets in CSAPR were used for this analysis. The CSAPR website is located at http://www.epa.gov/crossstaterule/techinfo.html.

Information regarding SO_2 and NO_x emission reductions necessary to achieve the future year modeled design values can be found in the "EmissionsSummaries.xlsx" spreadsheet under the Emissions Inventory Final Rule TSD section at EPA's CSAPR website for technical information : http://www.epa.gov/crossstaterule/techinfo.html. The spreadsheet shows the base case annual SO_2 and NO_x emissions for Indiana in 2012 and 2014. Indiana's total SO_2 and NO_x emission reductions between these two base cases scenarios are 89,222 tons, summarized in Table 10 on page 14. All surrounding states make similar significant reductions. Potentials to emit after controls for IPL Eagle Valley are 176.7 tons per year of NO_x and 30.9 tons per year of SO_2 for a total of 207.6 tons per year of NO_x and SO_2 emissions.

Table 10
EPA's Cross-State Air Pollution Rule Emission Summary for Indiana

	Pollutant	2012 Base Case Emissions (tons/year)	2014 Base Case Emissions (tons/year)	2012-2014 Difference (tons/year)
Indiana	SO_2	929,162	863,923	65,239
Indiana	NO_x	455,325	431,342	23,983
TOTAL				**89,222**

Annual $PM_{2.5}$ Modeling Results

The latest annual $PM_{2.5}$ design value (2010-2012) for the nearest $PM_{2.5}$ monitor to IPL Eagle Valley is the West 18th Street monitor in Marion County is 12.7 µg/m^3. The maximum annual $PM_{2.5}$ modeled concentration for the West 18th Street $PM_{2.5}$ monitor is 15.16 µg/m^3 for the 2012 base case and 14.65 µg/m^3 for the 2014 base case results. This is a decrease of 0.51 µg/m^3. Indiana's 2014 SO_2 emissions from EGUs were adjusted by 65,239 tons from the 2012 base case emissions and 2014 NO_x emissions were reduced by 23,983 for a total of 89,222 tons of SO_2 and NO_x. This particular monitoring site is not necessarily impacted by every EGU in Indiana, but in the surrounding states, hundreds of thousands of tons of annual SO_2 and NO_x emission reductions will occur by 2014, many of which will impact the Marion County monitor. Therefore, to estimate the impact of IPL Eagle Valley on modeled concentrations, the ratio of IPL Eagle Valley's SO_2 and NO_x emissions to Indiana's SO_2 and NO_x decreases from 2012 and 2014 base case CSAPR emissions were calculated. This ratio was then compared to the modeled annual $PM_{2.5}$ impact from the difference between the CSAPR 2012 and 2014 base case annual $PM_{2.5}$ modeling results.

1) **207.6 tons** IPL Eagle Valley's SO_2 and NO_x emissions / **89,222** tons of SO_2 and NO_x emissions reduced through CSAPR modeling = 0.233%

2) **0.233%** IPL Eagle Valley SO_2/NO_x emission ratio *** 0.51 µg/m^3** modeled annual $PM_{2.5}$ CSAPR results at the West 18th Street monitor = **0.0012 µg/m^3** of IPL Eagle Valley annual $PM_{2.5}$ impact

3) **0.0012 µg/m^3** IPL Eagle Valley's annual $PM_{2.5}$ impact /**14.65 µg/m^3** of 2014 Base Case annual $PM_{2.5}$ modeled results at the West 18th Street monitor = **0.008%** IPL Eagle Valley's impact on the 2014 modeled Base Case annual $PM_{2.5}$ results.

Tables showing projected base case 2014 $PM_{2.5}$ concentrations at existing monitoring sites versus control

strategy $PM_{2.5}$ concentrations are located in CSAPR_AQModeling.pdf, Appendix B, pages B-41 and B-42 for annual design values and pages B-70 to B-72 for 24-hour design values. 2014 Base represents anticipated 2014 emissions, 2014 Remedy represents the 2014 Base emissions with emission reductions from CSAPR factored into the modeling. Table 11 on page 15 shows the CSAPR annual $PM_{2.5}$ modeled concentrations at the Marion County $PM_{2.5}$ monitors and IPL Eagle Valley anticipated impacts.

It should be noted that the monitor at West 18th Street violates the 2012 $PM_{2.5}$ NAAQS. The impact from the new IPL Eagle Valley project taken by itself, even though below detection limits of a monitor, would contribute to a NAAQS violation. However, as noted in "Table 3: Projected Net Emissions Increase/Decreases based on 2010 and 2011 Actual Emissions (Tons per year)", emissions of SO_2, NO_x, and direct $PM_{2.5}$ will all be reduced by well over 1000 tons each per year. Further, permit condition "D.1.0 Retirement of Existing Operations. (a)" specifies that IPL Eagle Valley will permanently discontinue the operation of existing emission units prior to the startup of the turbines. Therefore, the new turbines will never operate at the same time as the old units and will emit substantially less pollutants, resulting in less impact on the West 18th Street monitor than the previous configuration.

Table 11
EPA's Cross-State Air Pollution Rule - Annual $PM_{2.5}$ Modeling Results

Monitor ID	County	2012 Base	2014 Base	2012 - 2014 Base ($\mu g/m^3$)	Anticipated Source Impact ($\mu g/m^3$)	Source Impact on 2014 Base Case Results (%)
180970081	Marion	15.16	14.65	0.51	0.0012	0.0081%
180970083	Marion	15.06	14.55	0.51	0.0012	0.0082%
180970043 *	Marion	13.45	12.97	0.48	0.0011	0.0086%

* Monitor not longer active

24-Hour $PM_{2.5}$ Modeling Results

The same emissions and impact analysis methodology used for the annual $PM_{2.5}$ impacts were used to determine the 24-hour $PM_{2.5}$ impacts from IPL Eagle Valley. The latest 24-hour $PM_{2.5}$ design value (2010-2012) for the nearest $PM_{2.5}$ monitor to IPL Eagle Valley is the West 18th Street monitor in Marion County is 29.0 $\mu g/m^3$. The maximum 24-hour $PM_{2.5}$ modeled concentration for the West 18th Street $PM_{2.5}$ monitor is 36.9 $\mu g/m^3$ for the 2012 base case and 35.1 $\mu g/m^3$ for the 2014 base case. This is a reduction of modeled concentration of 1.8 $\mu g/m^3$. To estimate the 24-hour impact of IPL Eagle Valley on modeled concentrations, the ratio of IPL Eagle Valley SO_2 and NO_x emissions and the CSAPR SO_2 and NO_x emission reductions were calculated. This ratio was then compared to the modeled 24-hour $PM_{2.5}$ impact from the difference between the CSAPR 2012 and 2014 base case 24-hour $PM_{2.5}$ modeling results.

1) **207.6 tons** IPL Eagle Valley SO_2 and NO_x emissions / **89,222 tons** of SO_2 and NO_x emissions reduced through CSAPR modeling = **0.233%**

2) **0.233%** IPL Eagle Valley SO_2/NO_x emission ratio *** 1.8 $\mu g/m^3$** modeled 24-hour $PM_{2.5}$ CSAPR results at the West 18th Street monitor = **0.0042 $\mu g/m^3$** of IPL Eagle Valley 24-hour $PM_{2.5}$ impact

3) **0.0042 $\mu g/m^3$** IPL Eagle Valley 24-hour $PM_{2.5}$ impact /**35.1 $\mu g/m^3$** of 2014 Base Case 24-hour $PM_{2.5}$ modeled results at the West 18th Street monitor = **0.012%** IPL Eagle Valley's impact on the 2014 modeled

Base Case 24-hour $PM_{2.5}$ concentration.

Modeling results below in Table 12 show 2012 and 2014 Base Case modeled 24-hour concentrations and the anticipated IPL Eagle Valley impacts, based on the emissions comparison and estimated impacts.

Table 12
EPA's Cross-State Air Pollution Rule - 24-Hour $PM_{2.5}$ Modeling Results

Monitor ID	County	2012 Base	2014 Base	2012 - 2014 Base ($\mu g/m^3$)	Anticipated Source Impact ($\mu g/m^3$)	Source Impact on 2014 Base Case Results (%)
180970081	Marion	36.9	35.1	1.8	0.0042	0.012%
180970083	Marion	34.5	32.7	1.8	0.0042	0.013%
180970043 *	Marion	33.5	32.1	1.4	0.0033	0.010%

* Monitor not longer active

Summary Annual and 24-Hour $PM_{2.5}$

IPL Eagle Valley's SO_2 and NO_x emissions were compared with U.S. EPA CSAPR modeling for annual and 24-hour $PM_{2.5}$ to determine what impacts of $PM_{2.5}$ may occur as a result of secondary $PM_{2.5}$ formation. When the IPL Eagle Valley emissions were compared with the amount of SO_2 and NO_x emission
reductions realized from the CSAPR modeling analysis and compared with CSAPR modeling results for annual and 24-hour, the impacts from IPL Eagle Valley on the nearest $PM_{2.5}$ monitor is anticipated to be minimal and will not have an effect on the attainment status of any $PM_{2.5}$ monitors in the area.

Part I - Summary of Air Quality Analysis

IPL Eagle Valley has applied for a PSD major source modification of their facility in Martinsville, Indiana with an increase in CO, NO_2, PM_{10}, $PM_{2.5}$, SO_2, and VOC emissions. ERM Consultants in Rolling Meadows, Illinois prepared the air quality analysis portion of the PSD permit application. Morgan County is designated as attainment for all criteria pollutants. CO, NO_2, PM_{10}, $PM_{2.5}$ and VOC emission rates associated with the proposed IPL Eagle Valley facility PSD major source modification did exceed the respective significant emission rates. Modeling results taken from the latest 12345 version of the AERMOD model showed the 1-hour and 8-hour CO and the annual PM_{10} modeled impacts were predicted to be less than the SILs and the NAAQS and PSD increment analyses were not required for these specific pollutant's time averaging periods. The NAAQS and PSD increment analysis were required for the 1-hour and annual NO_2, the 24-hour PM_{10} and $PM_{2.5}$, and the annual $PM_{2.5}$. Since there is currently no 1-hour NO_2 PSD increment, only an annual NO_2 PSD increment analysis was required for NO_2. The 1-hour NO_2 NAAQS analysis showed modeled violations, but the additional NO_2 contribution analysis showed the IPL Eagle Valley facility had an impact below the 1-hour NO_2 SIL for the violating receptors. IPL Eagle Valley did trigger the preconstruction monitoring for PM_{10} and $PM_{2.5}$ which was satisfied by existing monitoring data. A secondary ozone formation and a secondary $PM_{2.5}$ formation analysis were performed. The nearest Class I area is Mammoth Cave National Park near Cave City, Kentucky approximately 300 kilometers from the IPL Eagle Valley plant. An additional impact analysis was completed, but the operation of the proposed IPL Eagle Valley facility will have no significant impact on the region surrounding the facility or on the Class I area.

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analyses
Technical Support Document (TSD)
Prevention of Significant Deterioration (PSD)

Source Background and Description

Source Name:	**IPL Eagle Valley Generating Station**
Source Location:	**4040 Blue Bluff Road, Martinsville, Indiana, 46151**
County:	**Morgan**
SIC Code:	**4911**
Operation Permit No.:	**T109-26292-00004**
Operation Permit Issuance Date:	**December 2, 2008**
PSD/Significant Source Modification No.:	**T109-32471-00004**
Significant Permit Modification No.:	**T109-32476-00004**
Permit Reviewer:	**Josiah Balogun**

Proposed Expansion

IPL Eagle Valley Generating Station is proposing to replace the current coal and oil fired electric generating units at Indianapolis Power and Light's (IPL's) Eagle Valley Generating Station (EVGS) with a state-of-the-art, highly efficient combined cycle combustion turbine generation facility. The proposed combined cycle facility would include two nominal 192.5 Mega Watt (MW) combustion turbines with steam waste heat recovery to drive a nominal 271 MW steam turbine generator. The new facility would have a total nominal capacity of 656 MW (net). The exclusive fuel for the new combustion turbines will be natural gas.

IPL Eagle Valley Generating Station is required to undergo a review of control technology for pollutants above the significant levels under Federal and State Prevention of Significant Deterioration (PSD) Regulations.

IPL Eagle Valley Generating Station is located at the 4040 Blue Bluff Road, Martinsville, Indiana, in Morgan County. IPL Eagle Valley Generating Station submitted a PSD application to IDEM, OAQ on October 31, 2012.

Requirement for Best Available Control Technology (BACT)

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed modification because the modification has the potential to emit CO emissions greater than 100 tons per year, which exceeds the PSD threshold and significant levels for this pollutant. The BACT review also addressed the following pollutants: PM, PM_{10}, $PM_{2.5}$, VOC, CO, NOx, H_2SO_4 and Greenhouse Gases that exceeded the PSD significant levels.

See Appendix A – Emission Calculations – of this TSD for detailed Potential to Emit (PTE) calculations.

Proposed New Emission Units

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed emission units:

(a) Two (2) natural gas fired combustion turbine units each with a natural gas fired duct burner identified as EU-1 and EU-2, permitted in 2013, each with a total rated heat input capacity of 2,542 MMBtu/hr; with NO_x emissions controlled by low combustion burner design and Selective Catalytic Reduction (SCR), and each with an oxidation catalyst system to reduce emissions of CO and VOCs including formaldehyde, and exhausting to stacks S-1 and S-2. Each stack has continuous emissions monitors (CEMS) for NOx.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners and combustion turbines which are a source of emissions.

(b) One (1) natural gas fired Auxiliary Boiler, identified as emission unit EU-3, permitted in 2013, with a rated heat input capacity of 79.3 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions exhausting to stack S-3.

(c) One (1) natural gas fired Dew Point Heater, identified as emission unit EU-4, permitted in 2013, with a rated heat input capacity of 20.8 MMBtu/hr exhausting to stack S-4.

Insignificant and Trivial Activities

The source also consists of the following insignificant activities as defined in 326 IAC 2-7-1(21):

(a) One (1) distillate oil fired Emergency Generator, identified as emission unit EU-5, permitted in 2013, with a rated capacity of 1,826 HP and exhausting through stack S-5. [Under 40 CFR 60, Subpart IIII, the Emergency Generator is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Generator is considered new affected sources.]

(b) One (1) distillate oil fired Emergency Fire Pump, identified as emission unit EU-6, permitted in 2013, with a rated capacity of 500 HP and exhausting through stack S-6. [Under 40 CFR 60, Subpart IIII, the Emergency Fire Pump is considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the fired Emergency Fire Pump is considered new affected sources.]

(c) One (1) evaporative cooling tower, identified as emission unit U-7, rated with a circulation rate of 192,000 gpm to provide non-contact cooling water to the steam turbine condenser, permitted in 2013, and equipped with high efficiency drift eliminators.

(d) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit F-1, permitted in 2013, with fugitive emissions controlled by full enclosure.

(e) Fugitive equipment leaks from the natural gas supply lines, identified as F-2 controlled by a Leak Detection and Repair (LDAR) program.

(f) Three (3) Turbine Lube Demister Vents, permitted in 2013.

Summary of the Best Available Control Technology (BACT) Process

BACT is an emission limitation based on the maximum degree of pollution reduction of emissions, which is continuously achievable as a practical matter on a case-by-case basis. This BACT analysis takes into account the energy, environmental, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, work practices, and operational limitations. There will still be air pollution from this project; however, IPL Eagle Valley Generating Station will be required to demonstrate that the emissions will be reduced to the maximum extent.

Federal EPA generally requires an evaluation that follows a “top down” process. In this approach, the applicant identifies the best controlled similar source on the basis of controls required by regulation or permit, or controls achieved in practice. The highest level of control is then evaluated for technical feasibility. IDEM evaluates BACT based on a "top down" approach.

The five (5) basic steps of a top-down BACT analysis used by the Office of Air Quality (OAQ) to make BACT determinations are listed below:

Step 1: Identify Potential Control Technologies

The first step is to identify potentially “available” control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies and controls applied to similar source categories.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source specific factors related to safe and successful use of the controls. Innovative control means a control that has not been demonstrated in a commercial application on similar units. Innovative controls are normally given a waiver from the BACT requirements due to the uncertainty of actual control efficiency. IDEM evaluates any innovative controls if proposed by the source. IPL Eagle Valley Generating Station has not submitted any innovative control technology. Only available and proven control technologies are evaluated. A control technology is considered available when there are sufficient data indicating that the technology results in a reduction in emissions of regulated pollutants.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. The ranked alternatives are reviewed in terms of control effectiveness (percent pollutant removed). If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except, for the environmental analyses and any more stringent limits established from other RBLC Permits.

Step 4: Evaluate the Most Effective Controls and Document the Results

The fourth step begins with an evaluation of the remaining technologies under consideration for each pollutant of concern in regards to energy, environmental, and economic impacts for determining a final control technology. The highest ranked alternative is evaluated for environmental, energy and economic impacts specific to the proposed modification. If the analysis determines that the highest ranked control is not appropriate as BACT, due to any of the energy, environmental, and economic impacts, then the next most effective control is evaluated. The evaluation continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. In no case can the selected BACT be less stringent than any New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or Reasonably Available Control Technologies (RACT) standard emission limit.

Step 5: Select BACT

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible.

Particulate Matter (PM/PM_{10}) BACT – Combined Cycle Combustion Turbines EU-1 - EU-2

Step 1: Identify Potential Control Technologies

Emissions of PM and PM_{10} are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM and PM_{10} emissions are controlled through one of the following mechanisms:

(1) Fabric Filter Dust Collectors (Baghouses).

(2) Electrostatic Precipitators (ESP); and

(3) Wet Scrubbers;

(4) Cyclones or Multiclones;

(5) Fuel Specification; and

(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Fabric Filtration:

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired combustion turbines generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Baghouse is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Electrostatic Precipitators:
An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Natural-gas fired CCCTs generate low Particulate emissions and have large exhaust flow-rates, resulting in very low concentrations of Particulates. Electrostatic precipitator (ESPs) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an electrostatic precipitator is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Wet scrubbers:
A wet scrubber is an air pollution control device that removes particulate matter from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulate matter. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulate matter size decreases. Collection efficiencies also vary with scrubber type.

Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulate matter with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles which are difficult to remove in their dry form;

(4) PM in the presence of soluble gases; and

(5) PM in waste gas streams with high moisture content.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they are limited to lower waste gas flow rates and temperatures than ESPs or baghouses. Current wet scrubber designs accommodate air flow rates over 100,000 actual cubic feet per minute and temperatures of up to 750°F. The downstream corrosion or plume visibility problems can result unless the added moisture is removed from the gas stream.

Gas temperatures are between 40 to 750 °F. The typical waste stream inlet flow is 500 - 100,000 scfm (units in parallel can operate at greater flow rates). Effluent wastewater stream may require treatment. Sludge disposal may be costly. Wet scrubbers are particularly susceptible to corrosion. Natural-gas fired combustion turbines generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. A wet scrubber would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Cyclones:
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and Up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural-gas fired combustion turbines generate low Particulate emissions and have large exhaust flow rates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Fuel Specifications
Combusting only **c**lean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating PM and PM_{10} emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the combined cycle combustion turbines to keep them in good working order per the manufacturer's specifications will minimize PM and PM_{10} emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM and PM_{10} resulting from the operation of the combined cycle combustion turbines (EU-1 and EU-2).

(1) Fuel Specifications; and

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM and PM_{10} BACT determination along with the existing PM and PM_{10} BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Combined Cycle Combustion Turbines (EU-1 & EU-2)**	**2,542 MMBtu/hr, each**	**PM and PM_{10}: 16.8 pounds per hour and 0.0066 lbs/MMBtu, with duct firing based on 3-hr average**	**Good Combustion Practice and Fuel Specification**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
					13.9 pounds per hour and 0.0055 lbs/MMBtu without duct firing based on 3-hr average	
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Combined Cycle Combustion Turbines (CCCT1 -CCCT4)	2,300 MMBtu/hr	$PM/PM_{10}/PM_{2.5}$: 18 pounds per hour and 0.0078 lbs/MMBtu, with duct firing based on 3-hr average 15 pounds per hour and 0.0092 lbs/MMBtu without duct firing based on 3-hr average	Good Combustion Practice and Fuel Specification
LA-0254	Entergy Louisiana, LLC, Ninemile Point Electric Generating Plant - Jefferson, LA	08/16/2011	Natural gas-fired Combined Cycle Combustion Turbine, with fuel oil as back-up	7146 MMBtu/hr	$PM_{2.5}$ & PM_{10}: 26.23 lb/hr, hourly avg w/out duct burner; 33.16 lb/hr, hourly avg w/duct burner	None
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant - Mayes, OK	01/23/2009	Combined Cycle Cogeneration	> 25MW (1,882 MMBtu/hr)	PM_{10}: 6.59 lb/hr 3-hr avg; 0.0035 lb/MMBtu 24-hr avg	None (Oxidation catalyst was not used)
VA-0308	Virginia Electric & Power Co, Warren County Facility - Warren, VA	01/14/2008	Natural gas-fired Combined Cycle Combustion Turbine (2 units each with a HRSG and 500 MMbtu/hr DB)	1,717 MMBtu/hr	0.013 lb/MMBtu	None
MN-0071	Minnesota Municipal Power Agency, Fairbaul Tenergy Park - Rice, MN	06/05/2007	Natural gas-fired and Distillate fuel-fired Combined Cycle Combustion Turbine, with ultra-low sulfur diesel fuel as backup	1758 MMBtu/hr	0.01 lb/MMBtu (CTG NG or CTG & DB NG); 0.015 lb/MMBtu (CTG NG & DB oil); 0.03 lb/MMBtu (CTG oil & DB Not operate or NG or oil)	None
FL-0280	Florida Municipal Power Agency, Treasure Coast Energy Center - St. Lucie, FL	05/30/2006	Combined Cycle Combustion Turbine	170 MW	0.02 gr/dscf, natural gas specification; 0.0015% sulfur by weight fuel oil spec; 10% opacity	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
NY-0095	Caithness Bellport Energy Center - Suffolk, NY	05/10/2006	Natural gas-fired Combined Cycle Combustion Turbine	2221 MMBtu/hr	PM_{10}: 0.0055 lb/MMBtu w/out DB; 0.006 lb/MMBtu w/DB; Low sulfur fuel	None
			Fuel oil-fired Combined Cycle Combustion Turbine	2125 MMBtu/hr	PM_{10}: 0.0510 lb/MMBtu w/out DB 90-100% load; 0.0610 lb/MMBtu w/out DB 75-90% load; 0.0410 lb/MMBtu w/DB; Low sulfur fuel	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station- Yuma, AZ	12/01/2004	Natural gas-fired Combined Cycle Combustion Turbine and HRSG	170 MW	PM_{10}: 29.8 lb/hr, 3-hr avg	None
WI-0227	WE Energies (Port Washington Generating Station)- Washington, WI	10/13/2004	Natural gas-fired Combined Cycle Combustion Turbine (4 units with duct burner, HRSG)	2,096 MMBtu/hr	33.0 lb/hr PM/PM_{10}	None

The RBLC was reviewed and a summary of the BACT determinations for PM/PM_{10} fine emissions from combustion turbines is shown in the table above. It should be noted that there were no facilities identified that listed any add-on control technologies to limit particulate emissions from combustion turbines. These emission levels appear to be as much art as science, and are at most characterized by the case specific sulfur content of pipeline natural gas which varies from pipeline to pipeline. Gas pipeline sulfur content (as well as other potential impurities) must meet the ASTM specification for pipeline natural gas, but will vary over time and from pipeline to pipeline based on the source and quality of the gas wells serving the system. The quality of pipeline natural gas received on the day of a given performance test is outside the direct control of the facility that receives its natural gas from the pipeline, and this variability may in part help explain the variability in resulting particulate emissions that have been observed by the combustion turbine manufacturers.

Another case-specific factor may be ambient levels of airborne particulate emissions that were present on the day of the test. Such particulate emissions would not be expected to be removed in the combustion turbine inlet filter, but would be fine enough to go right on through. From evaluating EPA monitoring data, the that ambient levels of particulate vary with location and with local meteorology, and hence might influence tested emissions measured on one day versus another. This too represents a case-specific factor outside the control of the facility.

The selection of BACT must result in an emission limitation which is achievable (including a reasonable compliance margin) such that the facility has the ability to assure that compliance can be maintained. Since the facility has no active control over these site specific and case specific factors, and no known ability to reduce its emissions of $PM_{2.5}$ if needed to demonstrate compliance, BACT emission limitations for PM and PM_{10} must be set at levels for which compliance can be assured by the facility as a practical matter.

The RBLC search revealed only limited entries for $PM_{2.5}$ from a similar source. In all cases, the only available control for $PM/PM_{10}/PM_{2.5}$ for combustion turbines is the use of sweet natural gas (that is pipeline quality natural gas) and this "control technology", albeit variable from site to site and month to month, was determined to represent the top level of control for emission of fine particulate. The lowest BACT limitation resulting from exclusive use of sweet pipeline natural gas in similar combined cycle combustion turbines with duct firing and oxidation catalyst technology identified was for the Caithness project in NY with the identical "control technology" as the IPL project, and limitations of 0.0055 lb/MMBtu from the turbines only at full load (full load operation is defined by the test methods of 40 CFR 60) of 0.0055 lb/MMBtu, and at full load with duct firing at 0.0066 lb/MMBtu.

The Chouteau facility in Oklahoma permitted in 2009 has a limit of 0.0035 lbs/MMBtu (24-hour average) as compared with limit proposed by IPL of 0.0055 lbs/MMBtu (w/o duct burners). This value is an outlier and is specific to the design of this facility. All other demonstrated limits for F-class turbines are not less than 0.0055 lb/MMBtu.

The following has been proposed as BACT for PM and PM_{10} emissions from the proposed combined cycle combustion turbines, identified as EU-1 - EU-2:

1. The PM and PM_{10} emissions from the combined cycle combustion turbines identified as EU-1 - EU-2 shall not exceed 16.8 lb/hour and 0.0066 lb/MMBtu with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

2. The PM and PM_{10} emissions from the combined cycle combustion turbines identified as EU-1 - EU-2 shall not exceed 13.9 pounds per hour and 0.0055 lb/MMBtu without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for PM and PM_{10} for the combustion turbines (EU-1 - EU-2).

1. The PM and PM_{10} emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 16.8 pounds per hour, each and 0.0066 pounds per MMBtu, each with duct firing based on 3-hr average through the use of good combustion practices.

2. The PM and PM_{10} emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 13.9 pounds per hour, each and 0.0055 pounds per MMBtu, each without duct firing based on 3-hr average through the use of good combustion practices.

3. Only pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

Particulate Matter ($PM_{2.5}$) BACT – Combined Cycle Combustion Turbines EU-1 - EU-2

Step 1: Identify Potential Control Technologies

Emissions of $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Fabric Filter Dust Collectors (Baghouses).

(2) Electrostatic Precipitators (ESP); and

(3) Wet Scrubbers;

(4) Cyclones or Multiclones;

(5) Fuel Specification; and

(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Fabric Filtration:
A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired combustion turbines generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Baghouse is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Electrostatic Precipitators:
An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Natural-gas fired CCCTs generate low Particulate emissions and have large exhaust flow-rates, resulting in very low concentrations of Particulates. An electrostatic precipitator (ESP) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an electrostatic precipitator is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Wet scrubbers:
Wet high energy scrubber technology may also be employed to control solid particulate matter in certain industrial applications. Wet scrubbers operate in such a manner that flue gas passes through a water (or other solvent) stream whereby particles in the gas stream are removed through inertial impaction and/or condensation of liquid droplets on the particles in the gas

stream. High energy scrubbers are marginally effective at controlling fine filterable particulate, but are incapable of controlling condensable particulate below the flue gas saturation temperature.

In the case of natural gas-fired combustion turbines, whose particulate emissions are understood to exist almost exclusively as condensable $PM_{2.5}$, none of the identified traditional particulate control technologies identified would exhibit any meaningful emission control. None of these technologies has ever been applied to a combined cycle industrial combustion turbine and are certainly not demonstrated in practice in such an application. Further, their application would result in a significant increase in turbine backpressure, which would rob efficiency, and in order to produce the same output would result in a collateral increase in all other criteria air pollutants.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Cyclones:
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and Up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural-gas fired combustion turbines generate low Particulate emissions and have large exhaust flow rates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Fuel Specifications
Combusting only **c**lean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating $PM_{2.5}$ emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the combined cycle combustion turbines to keep them in good working order per the manufacturer's specifications will minimize $PM_{2.5}$ emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of $PM_{2.5}$ resulting from the operation of the combined cycle combustion turbines (EU-1 and EU-2).

(1) Fuel Specifications; and

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM_{2.5}$ BACT determination along with the existing $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Combined Cycle Combustion Turbines (EU-1 & EU-2)**	**2,542 MMBtu/hr, each**	**$PM_{2.5}$: 16.8 pounds per hour and 0.0066 lbs/MMBtu, with duct firing based on 3-hr average** **13.9 pounds per hour and 0.0055 lbs/MMBtu without duct firing based on 3-hr average**	**Good Combustion Practice and Fuel Specification**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Combined Cycle Combustion Turbines (CCCT1 -CCCT4)	2,300 MMBtu/hr	$PM/PM_{10}/PM_{2.5}$: 18 pounds per hour and 0.0078 lbs/MMBtu, with duct firing based on 3-hr average 15 pounds per hour and 0.0092 lbs/MMBtu without duct firing based on 3-hr average	Good Combustion Practice and Fuel Specification
LA-0254	Entergy Louisiana, LLC, Ninemile Point Electric Generating Plant - Jefferson, LA	08/16/2011	Natural gas-fired Combined Cycle Combustion Turbine, with fuel oil as back-up	7146 MMBtu/hr	$PM_{2.5}$ & PM_{10}: 26.23 lb/hr, hourly avg w/out duct burner; 33.16 lb/hr, hourly avg w/duct burner	None
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant - Mayes, OK	01/23/2009	Combined Cycle Cogeneration	> 25MW (1,882 MMBtu/hr)	PM_{10}: 6.59 lb/hr 3-hr avg; 0.0035 lb/MMBtu 24-hr avg	None (Oxidation catalyst was not used)

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
VA-0308	Virginia Electric & Power Co, Warren County Facility - Warren, VA	01/14/2008	Natural gas-fired Combined Cycle Combustion Turbine (2 units each with a HRSG and 500 MMbtu/hr DB)	1,717 MMBtu/hr	0.013 lb/MMBtu	None
MN-0071	Minnesota Municipal Power Agency, Fairbaul Tenergy Park - Rice, MN	06/05/2007	Natural gas-fired and Distillate fuel-fired Combined Cycle Combustion Turbine, with ultra-low sulfur diesel fuel as backup	1758 MMBtu/hr	0.01 lb/MMBtu (CTG NG or CTG & DB NG); 0.015 lb/MMBtu (CTG NG & DB oil); 0.03 lb/MMBtu (CTG oil & DB Not operate or NG or oil)	None
FL-0280	Florida Municipal Power Agency, Treasure Coast Energy Center - St. Lucie, FL	05/30/2006	Combined Cycle Combustion Turbine	170 MW	0.02 gr/dscf, natural gas specification; 0.0015% sulfur by weight fuel oil spec; 10% opacity	None
NY-0095	Caithness Bellport Energy Center - Suffolk, NY	05/10/2006	Natural gas-fired Combined Cycle Combustion Turbine	2221 MMBtu/hr	PM_{10}: 0.0055 lb/MMBtu w/out DB; 0.006 lb/MMBtu w/DB; Low sulfur fuel	None
			Fuel oil-fired Combined Cycle Combustion Turbine	2125 MMBtu/hr	PM_{10}: 0.0510 lb/MMBtu w/out DB 90-100% load; 0.0610 lb/MMBtu w/out DB 75-90% load; 0.0410 lb/MMBtu w/DB; Low sulfur fuel	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station-Yuma, AZ	12/01/2004	Natural gas-fired Combined Cycle Combustion Turbine and HRSG	170 MW	PM_{10}: 29.8 lb/hr, 3-hr avg	None
WI-0227	WE Energies (Port Washington Generating Station)-Washington, WI	10/13/2004	Natural gas-fired Combined Cycle Combustion Turbine (4 units with duct burner, HRSG)	2,096 MMBtu/hr	33.0 lb/hr PM/PM_{10}	None

The RBLC was reviewed and a summary of the BACT determinations for $PM/PM_{10}/PM_{2.5}$ fine emissions from combustion turbines is shown in the table above. It should be noted that there were no facilities identified that listed any add-on control technologies to limit particulate emissions from combustion turbines. These emission levels appear to be as much art as science, and are at most characterized by the case specific sulfur content of pipeline natural gas which varies from pipeline to pipeline. Gas pipeline sulfur content (as well as other potential impurities) must meet the ASTM specification for pipeline natural gas, but will vary over time and from pipeline to pipeline based on the source and quality of the gas wells serving the system. The quality of pipeline natural gas received on the day of a given performance test is outside the direct control of the facility that receives its natural gas from the pipeline, and this variability may in part help explain the variability in resulting particulate emissions that have been observed by the combustion turbine manufacturers.

Another case-specific factor may be ambient levels of airborne particulate emissions that were present on the day of the test. Such particulate emissions would not be expected to be removed in the combustion turbine inlet filter, but would be fine enough to go right on through. From evaluating EPA monitoring data, the that ambient levels of particulate vary with location and with local meteorology, and hence might influence tested emissions measured on one day versus another. This too represents a case-specific factor outside the control of the facility.

The selection of BACT must result in an emission limitation which is achievable (including a reasonable compliance margin) such that the facility has the ability to assure that compliance can be maintained. Since the facility has no active control over these site specific and case specific factors, and no known ability to reduce its emissions of $PM_{2.5}$ if needed to demonstrate compliance, BACT emission limitations for PM, PM_{10} and $PM_{2.5}$ must be set at levels for which compliance can be assured by the facility as a practical matter.

The RBLC search revealed only limited entries for $PM_{2.5}$ from a similar source. In all cases, the only available control for $PM/PM_{10}/PM_{2.5}$ for combustion turbines is the use of sweet natural gas (that is pipeline quality natural gas) and this “control technology”, albeit variable from site to site and month to month, was determined to represent the top level of control for emission of fine particulate. The lowest BACT limitation resulting from exclusive use of sweet pipeline natural gas in similar combined cycle combustion turbines with duct firing and oxidation catalyst technology identified was for the Caithness project in NY with the identical “control technology” as the IPL project, and limitations of 0.0055 lb/MMBtu from the turbines only at full load (full load operation is defined by the test methods of 40 CFR 60) of 0.0055 lb/MMBtu, and at full load with duct firing at 0.0066 lb/MMBtu.

The Chouteau facility in Oklahoma permitted in 2009 has a limit of 0.0035 lbs/MMBtu (24-hour average) as compared with limit proposed by IPL of 0.0055 lbs/MMBtu (w/o duct burners). This value is an outlier and is specific to the design of this facility. All other demonstrated limits for F-class turbines are not less than 0.0055 lb/MMBtu.

The following has been proposed as BACT for $PM_{2.5}$ emissions from the proposed combined cycle combustion turbines, identified as EU-1 - EU-2:

1. The $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 - EU-2 shall not exceed 16.8 lb/hour and 0.0066 lb/MMBtu with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

2. The $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 - EU-2 shall not exceed 13.9 pounds per hour and 0.0055 lb/MMBtu without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for $PM_{2.5}$ for the combustion turbines (EU-1 - EU-2).

1. The $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 16.8 pounds per hour, each and 0.0066 pounds per MMBtu, each with duct firing based on 3-hr average through the use of good combustion practices.

2. The $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall not exceed 13.9 pounds per hour, each and 0.0055 pounds per MMBtu, each without duct firing based on 3-hr average through the use of good combustion practices.

3. Only pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

Sulfuric Acid (H_2SO_4) BACT – Combined Cycle Combustion Turbines EU-1 & EU-2

Step 1: Identify Potential Control Technologies

Emissions of Sulfuric Acid (H_2SO_4) emissions depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. Sulfuric Acid (H_2SO_4) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Flue Gas Desulfurization (FGD) System);

(2) Dry Sorbent Injection; and

(3) Fuel Specification.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. H_2SO_4 emissions are not dependent upon combustion turbine properties such as size or burner design.

Step 2: Eliminate Technically Infeasible Options

Flue Gas Desulfurization (FGD) System
A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. FGD typically operates at a temperature of approximately 300°F to 700°F (wet) and 300°F to 1830°F (dry). The FGD has a waste stream inlet pollutant concentration of 2,000ppmv. Absorption of SO_2 is accomplished by the contact between the exhaust and an alkaline reagent, which results in the formation of neutral salts. Wet systems employ reagents using packed or spray towers and generate wastewater streams, while dry systems inject slurry reagent into the exhaust stream to react, dry and be removed downstream by particulate control equipment. By removing SO_2 from the exhaust stream, conversion of SO_2 to SO_3 and H_2SO_4 is reduced. Chlorine emissions can result in salt deposition within the absorber and in downstream equipment. Wet systems may require flue gas re-heating downstream of the absorber to prevent corrosive condensation. Inlet streams for dry systems must be cooled as appropriate, and dry systems require use of particulate controls to collect the solid netural salts.

FGD systems are not listed in the RBLC as BACT for the control of H_2SO_4 emissions for large combined cycle combustion turbines. Technology has not been applied to natural gas combined cycle combustion turbines due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of flue gas desulfurization system (FGD) is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Dry Sorbent Injection
A post-combustion technology in which a calcium or sodium-based sorbent reacts with SO_2 and SO_3 and is removed downstream by particulate control equipment. The reduced availability of SO_2 and SO_3 in the exhaust stream reduces H_2SO_4 formation, thereby reducing H_2SO_4 emissions. The system requires use of particulate controls to collect the reaction solids. Technology has not been applied to natural gas combined cycle combustion turbines due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction. Dry sorbent injection is not listed in the RBLC as BACT for the control of H_2SO_4 emissions for large combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of dry sorbent injection is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating H_2SO_4 emissions. Fuel Specifications is included in RBLC for the control of H_2SO_4 from combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of H_2SO_4 resulting from the operation of the combined cycle combustion turbines (EU-1 and EU-2).

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed H_2SO_4 BACT determination along with the existing H_2SO_4 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Combined Cycle Combustion Turbines (EU-**	**2,542 MMBtu/hr, each**	**H_2SO_4: 0.75 gr S/100 scf of natural gas**	**Fuel Specification**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
			1 & EU-2)			
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Combined Cycle Combustion Turbines (CCCT1 - CCCT4)	2,300 MMBtu/hr	H_2SO_4: 0.75 gr S/100 scf fuel sulfur	Fuel Specification
FL-0304	FMPA - Cane Island Power Park	9/8/2008	Combustion Turbines	1,860 CT 600 DB	2 gr S/100 scf gas	Fuel Specification
FL-0263	FP&L - Turkey Point Fossil Plant	2/8/2005	Combustion Turbines	1,608 CT 495 DB	2 gr S/100 scf gas	Fuel Specification
TX-0546	Pattillo Branch Power Company, LLC - Electric Generating Plant	6/17/2009	Combustion Turbines	444 DB	2 gr S/100 scf gas	Fuel Specification
FL-9002	FP&L Company - Cape Canaveral Energy Center	7/23/2009	Combustion Turbines	2,586 CT 460 DB	2 gr S/100 scf gas	Fuel Specification

IDEM is proposing a natural gas sulfur content limit of 0.75 gr S/100 scf which is the most stringent limit for H_2SO_4 emissions. Note that H_2SO_4 emissions depend on the sulfur content of the natural gas available to the facility. The proposed facility will have access to natural gas from a single supplier for the region, and will not have the option to receive natural gas from any other source or require the supplier to provide lower sulfur content fuel.

The following has been proposed as BACT for H_2SO_4 emissions from the proposed combined cycle combustion turbines, identified as EU-1 - EU-2:

(a) The H_2SO_4 emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall be limited by restricting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

(b) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for H_2SO_4 for the combined cycle combustion turbines (EU-1 - EU-2).

(a) The H_2SO_4 emissions from the combined cycle combustion turbines identified as EU-1 and EU-2 shall be limited by restricting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

(b) Only pipeline natural gas shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

Carbon Monoxide (CO) BACT – Combined Cycle Combustion Turbines EU-1 and EU-2

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer

(c) SCONOx Catalytic Absorption System;

(d) Catalytic oxidation;

(e) Good Combustion Controls; and

(f) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the waste gas containing CO is heated. The mixture continues to react as it flows through the combustion chamber. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

The required level of CO destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.
A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.
The operating temperature ranges from 1,100 - 1,200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source.

SCONOx Catalytic Absorption System
This control technology utilizes a single catalyst to remove NO_X, CO, and VOC through oxidation. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. The operating temperature ranges from 300 - 700^{o}F. The $SCONO_X$ Catalyst is sensitive to contamination by sulfur, so it must be used in conjunction with the $SCOSO_X$ catalyst, which favors sulfur compound absorption. This technology has only been demonstrated on units ranging from 5 to 45 MW.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a SCONOx Catalytic Absorption System is not a technically feasible option for combined cycle combustion turbines (EU-1 and EU-2) at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.
Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. This control is widely accepted as BACT for control of CO emissions from combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for combined cycle combustion turbines (EU-1 and EU-2) at this source.

Flare
Although the CO concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Good Combustion Controls
Good combustion controls is a continued operation of the CCCT at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation. Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - 70-90% destruction efficiency

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Combined Cycle Combustion Turbines (EU-1 & EU-2)**	**2,542 MMBtu/hr, each**	**CO: 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average**	**Oxidation Catalyst**
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Combined Cycle Combustion Turbines (CCCT1 -CCCT4)	2,300 MMBtu/hr	CO: 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average	Oxidation Catalyst

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
LA-0254	Entergy Louisiana, LLC, Ninemile Point Electric Generating Plant- Jefferson, LA	08/16/2011	Natural gas-fired Combined Cycle Combustion Turbine, with fuel oil as back-up	7146 MMBtu/hr	3.00 ppmvd @ 15% O_2 hourly avg	Oxidation catalyst
GA-0138	Live Oaks Company, LLC, Live Oaks Power Plant- Glynn, GA	04/08/2010	Natural gas-fired Combined Cycle Combustion Turbine	600 MW	2.0 ppm @ 15% O_2, 3-hr avg(w/out duct firing); 3.2 ppm @ 15% O_2, 3-hr avg(w/duct firing); 208 tpy	Catalytic oxidation
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant- Mayes, OK	01/23/2009	Combined Cycle Cogeneration	> 25MW (1,882 MMBtu/hr)	8.0 ppmv 1-hr avg; 51.32 ppm 3-hr avg; 1,596 lb/event 4-hr startup; 399 lb/event 1-hr shutdown	None
FL-0304	Florida Municipal Power Agency, Cane Island Power Park- Osceola, FL	09/08/2008	Natural gas-fired Combined Cycle Combustion Turbine	300 MW (1,860 MMBtu/hr)	6.00 ppmvd, 12-month; 8.00 ppmvd, 24-hr	None
FL-0305	Orlando Utilities Commission, OUC Curtis H. Stanton Energy Center- Orlando, FL	05/12/2008	Natural gas-fired Combined Cycle Combustion Turbine, with ultra-low sulfur diesel fuel as backup	300 MW (1,765 MMBtu/hr)	8.0 ppmvd @15%, 24-hr; 14 ppmvd @15% 24-hr during PA; 6 ppmvd @15% 12-month	None
LA-0224	Southwest Electric Power Co. Arsenal Hill Power Plant- Caddo, LA	03/20/2008	Combined Cycle Gas Turbines	2,110 MMBtu/hr	143.31 lb/hr; 10.0 ppmvd @ 15% O_2 annual average	None
CT-0151	Kleen Energy Systems, Inc.- Middlesex, CT	02/25/2008	Natural gas-fired combustion turbines	2.0 mmcf/hr	0.9 ppmvd @15% O_2, 1 hr-block and 4.3 lb/hr (w/out DB); 1.7 ppmvd @ 15% O_2 and 8.4 l/hr w/DB	Oxidation catalyst
VA-0308	Virginia Electric & Power Co, Warren	01/14/2008	Natural gas-fired Combined Cycle Combustion Turbine (2 units	1,717 MMBtu/hr	12.8 lb/hr w/DB; 7.2 lb/hr w/out DB; 1.30 ppmvd w/out power	Oxidation catalyst

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
	County Facility- Warren, VA		each with a HRSG and 500 MMbtu/hr DB)		augmentation	
MN-0071	Minnesota Municipal Power Agency, Fairbaul Tenergy Park- Rice, MN	06/05/2007	Natural gas-fired and Distillate fuel-fired Combined Cycle Combustion Turbine, with ultra-low sulfur diesel fuel as backup	1758 MMBtu/hr	No DB: 9.0 ppm 3-hr avg (gas), 20 ppm 3-hr avg (oil) DB: 11 ppm 3-hr avg (gas or oil)	None
FL-0285	Progress Energy Florida, Progress Bartow Power Plant- Pinellas, FL	01/26/2007	Natural gas-fired Combined Cycle Combustion Turbine	1,972 MMBtu/hr (1,280 MW)	8.0 ppmvd 24-hr block avg	None
NY-0095	Caithness Bellport Energy Center - Suffolk, NY	05/10/2006	Natural gas-fired Combined Cycle Combustion Turbine	2221 MMBtu/hr	2.0 ppmvd @ 15% O_2	Oxidation catalyst

The Virginia Electric & Power Company, in Warren County, Virginia, submitted a new application to revise the CO BACT limits, which have a broad range for the various modes of operation, with one limit has high as 2.5 ppm. It is difficult to compare the limits to IPL's proposed BACT limits due to this broad range. The lowest limit found in the RBLC was for the Kleen Energy Systems facility, located in Middlesex, Connecticut, which has a slightly lower BACT limit at 1.7 ppmvd. The "outlier" is the Kleen Energy Systems permit issued in 2008 in Connecticut which has a limit of 0.9 ppm with duct burners and 1.7 ppm without duct burners.

The permit for the Kleen Energy Systems facility in Middletown, Connecticut provides a BACT limit of 1.7 ppmvd at 15% O_2 on a 1-hour average basis during periods of operation with duct burners. The Kleen Energy Systems, LLC value is an outlier and is specific to the design of this facility. This limit is only slightly lower than the BACT for the IPL CCCT facility, and is reflective of the site-specific capabilities of this particular facility. Within the RBLC, all other demonstrated CO limits for F-class turbines are not less than 2.0 ppmv. No other constructed facilities have established a BACT limit less than 2.0 ppmvd. The proposed limit of 2.0 ppmvd @ 15% O_2 including duct firing is consistent with other demonstrated permit limits in the RBLC database.

The following has been proposed as BACT for CO emissions from the proposed combined cycle combustion turbines, identified as EU-1 - EU-2:

(1) The CO emissions from the combined cycle combustion turbines shall be controlled by catalytic oxidation

(2) The CO emissions shall not exceed 2.0ppmv @15% O2, based on a 3-hr average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for CO for the combined cycle combustion turbines:

(1) The CO emissions from the combined cycle combustion turbines shall be controlled by catalytic oxidation

(2) The CO emissions shall not exceed 2.0 ppmvd @15% O_2, based on a 3-hour average.

(3) Only pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

Carbon Monoxide (CO) BACT during Startup and Shutdown – Combined Cycle Combustion Turbines EU-1 and EU-2

Startup and shutdown events may result in temporarily elevated emissions of CO inherent to the method of operation of the combustion turbines. Emissions of products of incomplete combustion are normally controlled via precise fuel: air ratio control in the dry low NO_x combustor. Combustion turbines always default to diffusion flame and pilot mode (instead of lean pre-mix, DLN mode) when operating outside of their continuous operation design conditions, such as during a startup or shutdown. During the process of ramping and thermal "soaking" required during startup conditions, fuel:air ratios vary greatly before combustion temperatures are sufficient to burn out all of the fuel, resulting in short-term CO spikes. However, DLN mode operation is not available or technically feasible during these conditions, and higher CO concentrations (as well as potentially higher mass emissions) will result. During hot, warm and especially cold starts, the oxidation catalyst is also not at sufficient temperature to effectively complete oxidation of all products of incomplete combustion. For this combination of reasons, separate BACT limits are required to govern operations under these transient conditions, especially since these combustion turbines may be called upon for periodic cycling duty.

Step 1: Identify Potential Control Technologies

The RBLC, vendor data and literature were reviewed and a summary of the listed BACT determinations for CO from F Class industrial power generation combustion turbines. All of the entries, with the exception of one which netted out of PSD review, have attempted to limit the number and duration of startup events, and in particular cold startup events, to minimize the mass emissions of CO per event and/or per annum. Since the combustion conditions of a combustion turbine are highly transient during these events, there is no meaningful limitation described in units of ppmvd @ 15% O_2 because the event can be described as a series of spikes and plateaus. Since the most stringent CO emission levels during startup and shutdown are based on operating limitations, there is no applicable add-on control technology that has been demonstrated to be technically feasible for reduction of CO from industrial power generation turbines during startup and shutdown conditions.

The following are list of alternative potential control technologies that have been proposed to limit emissions of CO during startup and shutdown:

(a) Limited number of startup and shutdown events per year (and especially cold starts)

(b) Limited duration of various start events (i.e. "rapid start technology")

(c) Minimum firing of a single combustion turbine to maintain HRSG/STG temperatures as ready for warm or hot starts when practicable

(d) Use of auxiliary boiler firing to reduce HRSG/STG “cold iron” conditions to minimize cold and/or warm starts

Step 2: Eliminate Technically Infeasible Options

Operational limitation on number of startup events per year
The emission units being permitted are specifically defined as being capable of daily and weekend cycling in response to market conditions for power, and in order to serve this dispatch flexibility require the ability for daily hot starts, weekly warm starts and several cold starts each year. While the source does propose to limit the per-event and annual emissions of CO resulting from start events from the subject project, they could not be further limited without redefining the fundamental purpose of the project.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of operational limitation on number of startup events per year is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Limited duration of startup events
The duration of startup events is pre-defined by the combustion turbine vendors, is pre-programmed into the automated control systems, cannot be altered by the operator, and if attempted would void the warranties (and potentially damage the equipment).. While some vendors tout “rapid start technology”, especially on simple cycle engines, such technology can only be supplied within the design constraints of the case-specific combustion turbine and steam side design of the combined cycle system. Further limiting the duration of hot, warm and cold startup events does not represent a technically feasible CO reduction strategy during startup and shutdown of the proposed combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of limited duration of startup events is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Minimum firing of a single combustion turbine to minimize steam-side starts
This operating technique can and will be used as one option to minimize annual startup emissions (as well as to potentially minimize wear and tear on the equipment) when frequent cycling is required, and when market conditions support continuing to operate one machine at low load to enable rapid return to full firing when next called upon. This is a technique that favors the system’s maintenance schedule and, when economically advantageous represents a preferred operating strategy. However, such operation is not a technically feasible requirement or operating limitation for CO control during startups and shutdowns because market conditions may not support such operation within the definition and purpose of the project – to provide clean, reliable and low cost power to IPL’s customers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Minimum firing of a single combustion turbine to minimize steam-side starts is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Use of auxiliary boiler steam to minimize steam-side starts
This operating technique can and will be used as another option to minimize annual startup emissions (as well as to potentially minimize wear and tear on the equipment when frequent cycling is required, and when market conditions support auxiliary boiler firing to provide steam to the turbine seals, to minimize steam side thermal stress and to enable rapid return to full firing when next called upon. This is a technique that favors the system’s maintenance schedule and, when economically advantageous may represent a preferred operating strategy. However, such

operation is not a technically feasible requirement or operating limitation to reduce emissions of CO during startups and shutdowns because market conditions may not support such operation within the definition and purpose of the project – to provide clean, reliable and low cost power to IPL's customers

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of auxiliary boiler steam to minimize steam-side starts is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only controls determined to be technically feasible and demonstrated in practice for the proposed combustion turbines during startup and shutdowns are various combined cycle management techniques that may be implemented on a case-by-case basis to minimize per-event and rolling annual emissions by managing the number, type and duration of startup events.

Step 4: Evaluate the Most Effective Controls and Document the Results

BACT limits listed for other projects in the RBLC are highly project specific as they are influenced by the particular engine model, combined cycle steam side heat up limitations and the operational specifications of the facility itself based on local projected market conditions. The source proposes to employ operations management techniques, to the extent practicable, to limit per event and rolling 12-month emissions of CO during startups and shutdowns. These operational procedures are technically feasible only to the extent that they do not re-define the source being permitted. No other control alternatives have been identified as demonstrated in practice for a similar facility capable of any further reductions in CO under transient startup and shutdown conditions. Vendor data was used to define the levels of mass emissions per event that represent the top level of control during startup and shutdown of the proposed combustion turbines. Rolling 12-month emissions were determined based on assumptions regarding maximum annual cold, warm and hot starts to enable the facility to meet a range of projected market conditions in the IPL system.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for CO for the combined cycle combustion turbines:

The combined CO emissions from the combined cycle combustion turbines stacks during startup and shutdown events shall not exceed 3390 pounds per event and 565 tons per twelve (12) consecutive month period.

Volatile Organic Compounds (VOCs) BACT – Combined Cycle Combustion Turbines EU-1 - EU-2

Step 1: Identify Potential Control Technologies

Emissions of volatile organic compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer

(c) SCONOx Catalytic Absorption System;

(d) Catalytic oxidation;

(e) Good Combustion Controls; and

(f) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling VOC emissions. Upon passing through the flame, the waste gas containing VOC is heated. The mixture continues to react as it flows through the combustion chamber. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

The required level of VOC destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.
Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines at this source.

SCONOx Catalytic Absorption System
This control technology utilizes a single catalyst to remove NO_X, CO, and VOC through oxidation. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. The operating temperature ranges from 300 - 700^{o}F. The $SCONO_X$ Catalyst is sensitive to contamination by sulfur, so it must be used in conjunction with the $SCOSO_X$ catalyst, which favors sulfur compound absorption. This technology has only been demonstrated on units ranging from 5 to 45 MW.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a SCONOx Catalytic Absorption System is not a technically feasible option for combined cycle combustion turbines at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. This control is widely accepted as BACT for control of VOC emissions from combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for combined cycle combustion turbines at this source.

Flare
Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for VOC from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the combined cycle combustion turbines at this source

Good Combustion Controls
Good combustion controls is a continued operation of the CCCT at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation. Because VOC is

essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of VOC emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the combined cycle combustion turbines at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - 20-40% destruction efficiency

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Combined Cycle Combustion Turbines (EU-1 & EU-2)**	**2,542 MMBtu/hr, each**	**2.0 ppmvd @15% O_2, with duct burners based on 3-hr average** **1.0 ppmvd @15% O_2, without duct burners based on 3-hr average**	**Oxidation Catalyst**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Combined Cycle Combustion Turbines (CCCT1 -CCCT4)	2,300 MMBtu/hr	2.0 ppmvd @15% O_2, with duct burners based on 3-hr average 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average	Oxidation Catalyst
GA-0138	Live Oaks Company, LLC, Live Oaks Power Plant- Glynn, GA	04/08/2010	Natural gas-fired Combined Cycle Combustion Turbine	600 MW	2.0 ppm @ 15% O_2, 3-hr average	Catalytic oxidation, good combustion practices
LA-0224	Southwest Electric Power	03/20/2008	Combined Cycle Gas Turbines	2,110 MMBtu/hr	12.06lb/hr; 4.9 ppmvd @ 15%	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
	Co. Arsenal Hill Power Plant- Caddo, LA				O_2 annual average	
VA-0308	Virginia Electric & Power Co, Warren County Facility- Warren, VA	01/14/2008	Natural gas-fired Combined Cycle Combustion Turbine (2 units each with a HRSG and 500 MMbtu/hr DB)	1,944 MMBtu/hr	1.0 ppmvd w/out DB; 0.7 ppmvd w/DB	Oxidation catalyst
GA-0127	Southern Company / Georgia Power, Plant McDounough Combined Cycle- Cobb, GA	01/07/2008	Natural gas-fired Combined Cycle Combustion Turbine with diesel fuel as backup	254 MW	Gas: 1.80 ppm @ 15% O_2 3-hour w/duct burner; 1.0 ppm @ 15% O_2 w/out duct burner (LAER) Oil: 4.0 ppm @15% O_2, 3-hour (LAER)	Oxidation catalyst
MN-0071	Minnesota Municipal Power Agency, Fairbaul Tenergy Park- Rice, MN	06/05/2007	Natural gas-fired and Distillate fuel-fired Combined Cycle Combustion Turbine, with ultra-low sulfur diesel fuel as backup	1758 MMBtu/hr	1.5 ppmvd (CTG NG or CTG & DB NG); 3.0 ppmvd (CTG NG & DB oil); 3.5 ppmvd (CTG oil & DB Not operate or NG or oil)	None
FL-0285	Progress Energy Florida, Progress Bartow Power Plant- Pinellas, FL	01/26/2007	Natural gas-fired Combined Cycle Combustion Turbine with Duct Burner	1,972 MMBtu/hr (1,280 MW)	1.2 ppmvd @ 15% O_2 (CT only); 1.5 ppmvd @ 15% O_2 (CT and DB)	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station- Yuma, AZ	12/01/2004	Natural gas-fired Combined Cycle Combustion Turbine and HRSG	170 MW	3.0 ppm @ 15% O_2, 3-hr avg; 8.4 lb/hr 3-hr avg	Oxidation catalyst
WI-0227	WE Energies (Port Washington Generating Station)- Washington, WI	10/13/2004	Natural gas-fired Combined Cycle Combustion Turbine (4 units with duct burner, HRSG)	2,096 MMBtu/hr	1.2 ppmdv @15% O_2 calendar day avg w/DB; 0.8 ppmdv@ 15% O_2 calendar day avg w/out DB	Oxidation catalyst
NV-0037	Sempra Energy Resources, Copper Mountain	05/14/2004	Natural gas-fired Combined Cycle Combustion Turbine	600 MW	4.0 ppmvd @15% O_2, 3-hr avg w/DB; 1.9 ppmvd @ 15@	Oxidation catalyst

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
	Power- Clark, NV				$O_2$3-hr avg w/out DB (LAER)	

There are three other sources which have been identified as having lower limits: the Chouteau facility in Oklahoma which has a limit of 0.3 ppm; a Virginia Electric Power facility permitted in 2009 with limits of 1 ppm with duct burning and 0.7 ppm without duct burning; and the Progress Energy facility permitted in 2007 in Florida with limits of 1.5 ppm with duct burning and 1.2 ppm without duct burning.

The limits in the Virginia Electric and Power - Warren County Facility are for G-class turbines, not F-class turbines like those for the proposed project. Commercial operation is scheduled for late 2014 or early 2015. Therefore, BACT limits have not been demonstrated.

The Associated Electric Cooperative, Inc. – Chouteau Power Plant value is an outlier and is specific to the design of this facility. All other demonstrated limits for F-class turbines are not less than 1.0 ppmvd without duct burner firing. In addition, it does not appear that the Chouteau facility is permitted with an oxidation catalyst and has a CO limit of 8 ppm, and as such the VOC limit represented for this facility is inconsistent for this facility.

Carbon Monoxide (CO) is a product of incomplete combustion, whereby trace quantities of carbon molecules in the hydrocarbon fuel fail to become oxidized completely to CO_2, and are emitted as the fairly unstable molecule CO. CO emissions from low level sources such as automobiles in confined spaces (such as urban city canyons) pose a threat to air quality. VOC is defined as non-methane, non-ethane hydrocarbons (NMHC) which are also emitted from combustion turbines as products of incomplete combustion, in this case when molecules of both hydrogen and carbon pass though the combustion system without being fully oxidized (combusted).

The information provided in the RBLC for the Progress Energy facility in Florida does not indicate that an oxidation catalyst or other control method will be used and the CO limit in that permit is 8 ppm (24-hour average). As such, the VOC limit identified in the RBLC is inconsistent for this facility.

IDEM cannot directly compare the proposed IPL limits with the limits cited above for the Port Washington Generating station since the averaging periods for the different limits differ significantly. The Port Washington facility has a slightly lower numeric value but compliance is determined over a daily average rather than over a 3-hour period. A 3-hour period as proposed by IPL is a more stringent averaging period than daily. Based on the different averaging periods IDEM do not believe the limits for the Port Washington facility are in fact more stringent than the limit proposed by IPL. IDEM also believe that the 3-hour averaging period is a more appropriate averaging period for VOC emissions as it is consistent with the standard three one-hour source tests compliance basis.

Therefore, the proposed limits of 1.0 ppmvd @15% O_2, without duct burners, and of 2.0 ppmvd @15% O_2, with duct burners, based on a 3-hr average are consistent with all other limits in the RBLC for this type of operation.

The following has been proposed as BACT for VOC emissions from the proposed combined cycle combustion turbines, identified as EU-1 - EU-2:

(1) The VOC emissions from the CCCT shall be controlled by catalytic oxidation.

(2) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average.

(3) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for VOC for the combined cycle combustion turbines:

(1) The VOC emissions from the CCCTs shall be controlled by catalytic oxidation

(2) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average.

(3) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average.

(4) Only pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

Volatile Organic Compounds (VOC) BACT during Startup and Shutdown – Combined Cycle Combustion Turbines EU-1 and EU-2

Startup and shutdown events may result in temporarily elevated emissions of VOC inherent to the method of operation of the combustion turbines. Emissions of products of incomplete combustion are normally controlled via precise fuel: air ratio control in the dry low NO_x combustor. Combustion turbines always default to diffusion flame and pilot mode (instead of lean pre-mix, DLN mode) when operating outside of their continuous operation design conditions, such as during a startup or shutdown. During the process of ramping and thermal “soaking” required during startup conditions, fuel:air ratios vary greatly before combustion temperatures are sufficient to burn out all of the fuel, resulting in short-term CO spikes. However, DLN mode operation is not available or technically feasible during these conditions, and higher VOC concentrations (as well as potentially higher mass emissions) will result. During hot, warm and especially cold starts, the oxidation catalyst is also not at sufficient temperature to effectively complete oxidation of all products of incomplete combustion. For this combination of reasons, separate BACT limits are required to govern operations under these transient conditions, especially since these combustion turbines may be called upon for periodic cycling duty.

Step 1: Identify Potential Control Technologies

The RBLC, vendor data and literature were reviewed and a summary of the listed BACT determinations for VOC from F Class industrial power generation combustion turbines. All of the entries, with the exception of one which netted out of PSD review, have attempted to limit the number and duration of startup events, and in particular cold startup events, to minimize the mass emissions of VOC per event and/or per annum. Since the combustion conditions of a combustion turbine are highly transient during these events, there is no meaningful limitation described in units of ppmvd @ 15% O_2 because the event can be described as a series of spikes and plateaus. Since the most stringent VOC emission levels during startup and shutdown are based on operating limitations, there is no applicable add-on control technology that has been demonstrated to be technically feasible for reduction of VOC from industrial power generation turbines during startup and shutdown conditions.

The following are list of alternative potential control technologies that have been proposed to limit emissions of VOC during startup and shutdown:

(a) Limited number of startup and shutdown events per year (and especially cold starts)

(b) Limited duration of various start events (i.e. “rapid start technology”)

(c) Minimum firing of a single combustion turbine to maintain HRSG/STG temperatures as ready for warm or hot starts when practicable

(d) Use of auxiliary boiler firing to reduce HRSG/STG “cold iron” conditions to minimize cold and/or warm starts

Step 2: Eliminate Technically Infeasible Options

Operational limitation on number of startup events per year
The emission units being permitted are specifically defined as being capable of daily and weekend cycling in response to market conditions for power, and in order to serve this dispatch flexibility require the ability for daily hot starts, weekly warm starts and several cold starts each year. While the source does propose to limit the per-event and annual emissions of VOC resulting from start events from the subject project, they could not be further limited without redefining the fundamental purpose of the project.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of operational limitation on number of startup events per year is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Limited duration of startup events
The duration of startup events is pre-defined by the combustion turbine vendors, is pre-programmed into the automated control systems, cannot be altered by the operator, and if attempted would void the warranties (and potentially damage the equipment).. While some vendors tout “rapid start technology”, especially on simple cycle engines, such technology can only be supplied within the design constraints of the case-specific combustion turbine and steam side design of the combined cycle system. Further limiting the duration of hot, warm and cold startup events does not represent a technically feasible VOC reduction strategy during startup and shutdown of the proposed combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of limited duration of startup events is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Minimum firing of a single combustion turbine to minimize steam-side starts
This operating technique can and will be used as one option to minimize annual startup emissions (as well as to potentially minimize wear and tear on the equipment) when frequent cycling is required, and when market conditions support continuing to operate one machine at low load to enable rapid return to full firing when next called upon. This is a technique that favors the system’s maintenance schedule and, when economically advantageous represents a preferred operating strategy. However, such operation is not a technically feasible requirement or operating limitation for VOC control during startups and shutdowns because market conditions may not support such operation within the definition and purpose of the project – to provide clean, reliable and low cost power to IPL’s customers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Minimum firing of a single combustion turbine to minimize steam-side starts is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Use of auxiliary boiler steam to minimize steam-side starts
This operating technique can and will be used as another option to minimize annual startup emissions (as well as to potentially minimize wear and tear on the equipment when frequent cycling is required, and when market conditions support auxiliary boiler firing to provide steam to the turbine seals, to minimize steam side thermal stress and to enable rapid return to full firing when next called upon. This is a technique that favors the system's maintenance schedule and, when economically advantageous may represent a preferred operating strategy. However, such operation is not a technically feasible requirement or operating limitation to reduce emissions of VOC during startups and shutdowns because market conditions may not support such operation within the definition and purpose of the project – to provide clean, reliable and low cost power to IPL's customers

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Use of auxiliary boiler steam to minimize steam-side starts is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only controls determined to be technically feasible and demonstrated in practice for the proposed combustion turbines during startup and shutdowns are various combined cycle management techniques that may be implemented on a case-by-case basis to minimize per-event and rolling annual emissions by managing the number, type and duration of startup events.

Step 4: Evaluate the Most Effective Controls and Document the Results

BACT limits listed for other projects in the RBLC are highly project specific as they are influenced by the particular engine model, combined cycle steam side heat up limitations and the operational specifications of the facility itself based on local projected market conditions. The source proposes to employ operations management techniques, to the extent practicable, to limit per event and rolling 12-month emissions of VOC during startups and shutdowns. These operational procedures are technically feasible only to the extent that they do not re-define the source being permitted. No other control alternatives have been identified as demonstrated in practice for a similar facility capable of any further reductions in VOC under transient startup and shutdown conditions. Vendor data was used to define the levels of mass emissions per event that represent the top level of control during startup and shutdown of the proposed combustion turbines. Rolling 12-month emissions were determined based on assumptions regarding maximum annual cold, warm and hot starts to enable the facility to meet a range of projected market conditions in the IPL system.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for VOC for the combined cycle combustion turbines:

The combined VOC emissions from the combined cycle combustion turbines stacks, during startup and shutdown events, shall not exceed 146 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Nitrogen Oxide (NOx) BACT– Combined Cycle Combustion Turbines EU-1 - EU-2

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR);

(b) Selective Non-Catalytic Reduction (SNCR);

(c) Low NOx Combustors;

(d) Flue gas Recirculation;

(e) Catalytic Combustors;

(f) SCONOx;

(g) Natural gas Firing; and

(h) Water Injection.

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) is a well proven technology for reducing NOx emissions from CCCTs. The SCR technology mixes exhaust gases with ammonia (which may be received and stored as anhydrous ammonia, aqueous ammonia or liquid urea) which then pass through a catalyst reactor to reduce NOx to N_2 and water.

The most important factor affecting SCR efficiency is catalyst operating temperature. SCR can operate in a flue gas window ranging from 500°F to 1100°F, although best NOx reduction performance occurs at the higher end of this range. Temperatures below the optimum decrease catalyst activity and allow both NOx and NH_3 to pass through unreacted; above the optimum range, ammonia will oxidize to form additional NOx. SCR NOx reduction efficiency is also largely dependent on gaseous mixing and residence time of injected ammonia as well as the stoichiometric molar ratio of NH_3: NOx. For example, variation of the theoretical 1:1 molar ratio of NH_3: NOx to 0.5:1 ratio would theoretically reduce the removal efficiency to 50%. However, even at the theoretical molar ratio, 100% reduction cannot be achieved. The HRSG is a fixed geometry device with uneven temperature, flow rate, NOx concentration and NH_3 concentration, especially considering variations in operating load, ramping and duct firing, with very little available mixing and reaction time between the ammonia injection grid and catalyst bed. Due to these practical limitations, it is necessary to over-inject ammonia to drive NOx to very low levels, meaning that surplus ammonia will be emitted from the stack as ammonia "slip." Recent permits for large combined cycle, natural gas-fired combustion turbines limit NOx emissions to around 2 ppmvd @ 15% O_2 including duct firing, with ammonia slip limits as high as 10 ppm. Such control systems have been operated successfully in a number of similar applications for many years and are considered to be reliable and well proven state-of-the-art NOx control technology. SCR technology in combination with dry low NOx combustors is also the "top" level of control listed in the RBLC.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is a technically feasible option for the combined cycle combustion turbines at this source.

Selective Non-Catalytic Reduction (SNCR)
Selective Non-Catalytic Reduction (SNCR) is not applicable for control of NOx from combustion turbines. The SNCR technology removes NOx through ammonia or urea injection into boiler flue gas within a temperature range of 1600°F to 2000°F and without the use of a catalyst. SNCR has never been applied to a combustion turbine because combustion turbines lack the physical time, turbulence and temperature window for the technology to work. SNCR does not represent a technically feasible alternative for NOx control from the proposed combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is not a technically feasible option for the combined cycle combustion turbines at this source.

Dry Low NO_x (DLN) Combustors
Low NO_x Burner (LNB) technology (in combustion turbines referred to as dry low NOx combustor/lean pre-mix combustor technology) reduces the formation of NOx through control of the fuel-air mixture to limit peak flame temperature and oxygen availability in the peak temperature zone of the flame. This technology is capable of reducing NOx emissions to the range of 9-25 ppmvd in combustion turbines, and is employed nearly universally on new, natural gas-fired power generation turbines in the U.S.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that dry low NOx (DLN) combustor is a technically feasible option for the combined cycle combustion turbines at this source.

Flue Gas Recirculation (FGR)
FGR reduces NO_x emissions by recirculating a portion of the exhaust gas back into the combustion flame. This results in lower combustion temperatures and oxygen levels in the combustion air/flue gas mixture, thus retarding the formation of thermal NOx. Internal flue gas recirculation (within the combustors) is employed in the design of all combustion turbine DLN technology, and therefore does not represent a separate technology for consideration as a candidate for BACT for these units. In any event internal FGR is inherently incorporated into the design of all modern DLN combustors.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that flue gas recirculation (FGR) is a technically feasible option for the combined cycle combustion turbines at this source.

Catalytic Combustors
Catalytic combustors burn the fuel at low temperature across a catalyst, hence suppressing the formation of NOx. The only known applications are on very small (1.5 MW scale) Kawasaki combustion turbines. Catalytic combustors cannot achieve the same levels of control demonstrated by SCR, and would provide no control of duct burner emissions. This technology is not commercially available, and has never been demonstrated in practice on any F Class Industrial combustion turbine.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the catalytic combustor is not a technically feasible option for the combined cycle combustion turbines at this source.

SCONOx
SCONOx is a potassium based NOx absorption and regeneration technology that has been installed commercially on a few < 10 MW combined heat and power combustion turbines. It has never been applied or demonstrated in practice on F Class combustion turbines. While SCONOx technology enjoyed brief interest in the 1990s, it has failed to become a viable commercial product. Finally, even if it were deemed transferrable technology, it is not capable of the level of

NOx control that has been demonstrated by SCR. Due to its lack of application, availability or demonstration on F Class industrial power generation combustion turbines, SCONOx technology does not represent technically feasible candidate for NOx control from the proposed combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that SCONOx is not a technically feasible option for the combined cycle combustion turbines at this source.

Natural Gas Firing
Natural gas does not contain fuel bound nitrogen, and therefore gas-only fired combustion turbines are capable of lower (down to single digits) NOx emissions with dry low NOx combustors than those fired with liquid fuels. The lowest NOx emissions listed in the RBLC are all for combustion turbines firing natural gas. The proposed project will fire exclusively natural gas and will incorporate this control technique into its best available control strategy.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the natural gas firing is a technically feasible option for the combined cycle combustion turbines at this source.

Water Injection
Water injection is a control technique designed to lower peak flame temperature, and therefore NOx formation, within the turbine combustors. This technology is generally employed on liquid fuel-fired units for which dry low NOx combustors are unavailable, but is not capable of equivalent NOx reduction performance to dry low NOx technology on gas-fired units.

Based on the information reviewed for this BACT and LAER determination, IDEM, OAQ has determined that the water injection is a technically feasible option for the combined cycle combustion turbines at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Selective Catalytic Reduction — (Up to 90% NOx Reduction)

(2) Dry Low NOx Combustors — (Up to 60% NOx Reduction)

(3) Flue Gas Recirculation;

(4) Natural gas firing — (Up to 50% NOx Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Combined Cycle Combustion Turbines (EU-1 & EU-2)**	**2,542 MMBtu/hr, each**	**NOx: 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average**	**SCR and dry low NOx combustors**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Combined Cycle Combustion Turbines (CCCT1 -CCCT4)	2,300 MMBtu/hr	NOx: 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average	SCR and DLN Burners
GA-0138	Live Oaks Company, LLC, Live Oaks Power Plant	04/08/2010	Natural gas-fired Combined Cycle Combustion Turbine	600 MW	2.5 ppm @ 15% O_2, 3-hr average; 87 tpy	Dry Low-NO_x burners, SCR
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant	01/23/2009	Combined Cycle Cogeneration	> 25MW (1,882 MMBtu/hr)	2.0 ppm 1-hr avg @ 15% O_2; 15.25 lb/hr 1-hr avg; 568 lb/event 4-hr startup; 142 lb/event 1-hr shutdown	Dry Low-NO_x burners, SCR
FL-0304	Florida Municipal Power Agency, Cane Island Power Park	09/08/2008	Natural gas-fired Combined Cycle Combustion Turbine	300 MW (1,860 MMBtu/hr)	2.0 ppmvd 24-hr	SCR
FL-0305	Orlando Utilities Commission, OUC Curtis H. Stanton Energy Center	05/12/2008	Natural gas-fired Combined Cycle Combustion Turbine, with ultra-low sulfur diesel fuel as backup	300 MW (1,765 MMBtu/hr)	8.0 ppmvd @ 15% O_2, 24-hr average (oil); 2.0 ppmvd @ 15% O_2, 24-hr average (gas)	Low- NO_x burners and SCR water injection
LA-0224	Southwest Electric Power Co. Arsenal Hill Power Plant	03/20/2008	Combined Cycle Gas Turbines	2,110 MMBtu/hr	30.15 lb/hr; 4.0 ppmvd @ 15% O_2 annual average	Low- NO_x burners, duct burners combined with SCR
CT-0151	Kleen Energy Systems, Inc.	02/25/2008	Natural gas-fired combustion turbines	2.0 mmcf/hr	2.0 ppmvd @ 15% O_2, 1-hr block (LAER)	Low- NO_x burners, SCR
VA-0308	Virginia Electric & Power Co, Warren County Facility	01/14/2008	Natural gas-fired Combined Cycle Combustion Turbine (2 units each with a HRSG and 500 MMbtu/hr DB)	1,944 MMBtu/hr	2.0 ppm, 17.9 lb/hr	2-stage premix NO_x combustion, SCR
FL-0285	Progress Energy Florida, Progress Bartow Power Plant	01/26/2007	Natural gas-fired Combined Cycle Combustion Turbine	1,972 MMBtu/hr (1,280 MW)	15 ppmvd 30-day basis (gas); 42 ppmvd 30-day basis (oil);	Water injection, if needed (project netted out of PSD review)
FL-0280	Florida Municipal Power	05/30/2006	Combined Cycle Combustion Turbine	170 MW	2.0 ppmvd 24-hour block (gas); 8.0 ppmvd 24-	SCR

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
	Agency, Treasure Coast Energy Center				hour block (oil)	
NY-0095	Caithness Bellport Energy Center	05/10/2006	Natural gas-fired Combined Cycle Combustion Turbine	2221 MMBtu/hr	2.0 ppmvd @ 15% O_2	SCR
			Fuel oil-fired Combined Cycle Combustion Turbine	2125 MMbtu/hr	6.0 ppmvd @ 15% O_2w/out DB; 6.8 ppmvd @ 15% O_2w/DB	SCR
WI-0227	WE Energies (Port Washington Generating Station)	10/13/2004	Natural gas-fired Combined Cycle Combustion Turbine (4 units with duct burner, HRSG)	2,096 MMBtu/hr	3.0 ppm @ 15% O_2, 30-day rolling avg, each	Dry Low-NO_x burners, SCR
NV-0037	Sempra Energy Resources, Copper Mountain Power	05/14/2004	Natural gas-fired Combined Cycle Combustion Turbine	600 MW	2.0 ppmvd @ 15% O_2 3-hr avg; 17.92 lb/hr	Dry Low-NO_x combustor, steam injection, and SCR
AZ-0049	Allegheny Energy Supply, LLC La Paz Generating Facility	09/04/2003	Combined Cycle Combustion Turbines and HRSGs	1080 MW	2.0 ppmvd @ 15% O 3-hr avg; 16.0 lb/hr	Low- NO_x burners and SCR
CA-0997	Sacramento Municipal Utility District	09/01/2003	Natural gas-fired Turbines	1,611 MMBtu/hr	2.0 ppmvd @ 15% O_2 (LAER)	SCR
PA-0226	Limerick Partners, LLC Power Station	04/09/2002	Natural gas-fired Combined Cycle Turbine	550 MW	2.0 ppmvd @ 15% O_2 (LAER)	Low- NO_x burners
PA-0188	Fairless Energy LLC	03/28/2002	Natural gas-fired Combined Cycle Turbine	1,190 MW	2.5 ppmvd @ 15% O_2 (LAER)	Dry Low-NO_x burners, SCR
PA-0223	Duke Energy Fayette, LLC	01/30/2002	Natural gas-fired Combined Cycle Turbine	280 MW	2.5 ppmvd @ 15% O_2 (LAER)	Low- NO_x burners, SCR

This top level of control reflects the sequential combination of exclusive natural gas firing, dry low NOx combustors and SCR, and this combination of control technology reflects the maximum or "top" level of control that has been demonstrated in practice in similar applications. The lowest limitation identified that has been achieved in practice for similar duct fired combustion turbines is an emission rate of 2 ppmvd NOx @ 15% O_2 from the combustion turbines during normal (non-startup, shutdown or malfunction) operation, to be continuously monitored using Part 60 and 75 certified continuous emissions monitoring systems (CEMS). This control technology and emission limitation also constitutes BACT for NOx for normal operation of the CCCTs.

The following has been proposed as BACT for NOx emissions from the proposed combined cycle combustion turbines, identified as EU-1 - EU-2:

(1) The NOx emissions from the CCCT shall be controlled by Selective Catalytic Reduction and Dry Low NOx combustors.

(2) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hr average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for NOx for the combined cycle combustion turbines:

(1) The NOx emissions from the CCCTs shall be controlled by Selective Catalytic Reduction and Dry Low NOx combustors.

(2) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hr average.

(3) Only pipeline natural gas only shall be fired in the combined cycle combustion turbines identified as EU-1 and EU-2.

Nitrogen Oxide (NOx) BACT during Startup and Shutdown – Combined Cycle Combustion Turbines EU-1 and EU-2

Startup and shutdown events may result in temporarily elevated emissions of NOx inherent to the diffusion flame startup mode of the combustion turbines. Combustion turbines always default to diffusion flame and pilot mode (instead of lean pre-mix, DLN mode) when operating outside of their continuous operating regime, such as during a startup or shutdown. Thus, DLN technology is not technically feasible during these operating conditions, and higher NOx concentrations (although not necessarily higher mass emissions) will result. During hot, warm and especially cold starts, the SCR catalyst is not at sufficient temperature to initiate ammonia injection for the NOx control reaction to proceed. For this combination of reasons, separate BACT limits are proposed for these transient conditions, since the proposed combustion turbines may be called upon for periodic cycling duty.

Step 1: Identify Potential Control Technologies

The RBLC, vendor data and the literature were reviewed and a summary of the listed BACT determinations for F Class industrial power generation combustion turbines. All of the entries, with the exception of one which netted out of PSD review, have attempted to limit the number and duration of startup events, and in particular cold startup events, to minimize the mass emissions of NOx per event and/or per annum. Since the combustion conditions of a combustion turbine are transient during these events, there is no meaningful limitation described in units of ppmvd @ 15% O_2 because the event can be described as a series of spikes and plateaus. According to the data reviewed there is no applicable add-on control technology that has been demonstrated to be technically feasible for reduction of NOx from industrial power generation turbines during startup and shutdown conditions.

The following is a list of alternative potential control technologies that have been proposed to limit emissions of NOx during startup and shutdown:

(a) Limited number of startup and shutdown events per year (and especially cold starts);

(b) Limited duration of various start events (i.e. “rapid start technology”);

(c) Minimum firing of a single combustion turbine to maintain HRSG/STG temperatures as ready for warm or hot starts;

(d) Use of auxiliary boiler firing to reduce HRSG/STG “cold iron” conditions to minimize cold and/or warm starts.

Step 2: Eliminate Technically Infeasible Options

Operational limitation on number of startup events per year
The emission units being permitted are specifically defined as being capable of daily and weekend cycling in response to market conditions for power, and in order to serve this dispatch flexibility require the ability for daily hot starts, weekly warm starts and several cold starts each year. While IPL does propose to limit the annual start events from the subject project, the events could not be further limited without redefining the purpose of the project.
Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of operational limitation on number of startup events per year is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Limited duration of startup events
The duration of startup events is pre-defined by the combustion turbine vendors, is pre-programmed into the automated control systems, cannot be altered by the operators and to do so would void the warranties (and potentially damage the equipment). While some vendors tout “rapid start technology”, especially on simple cycle engines, such technology can only be supplied within the design constraints of the combustion turbine and steam system equipment (HRSG, steam turbine generator, pumps and piping, etc.) being purchased. The design of the complete combined cycle plant, and especially the steam side, is a case specific feature of each project being permitted. Further limiting the duration of hot, warm and cold startup events does not represent a technically feasible NOx reduction strategy for minimizing the duration of, and resulting emissions from startup and shutdown of the proposed combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of limited duration of startup events is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Minimum firing of a single combustion turbine to minimize steam-side starts
This operating technique can and will be used to minimize wear and tear on the equipment when frequent cycling is required, and when market conditions support continuing to operate one machine at low load to enable rapid return to full firing the next day, etc. This is a technique that favors the system’s maintenance schedule and, when economically advantageous represents the preferred operating strategy. However, such operation is not a technically feasible requirement or operating limitation for NOx control during startups and shutdowns because market conditions may not support such operation within the definition and purpose of the project – to provide clean, reliable and low cost power to our customers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Minimum firing of a single combustion turbine to minimize steam-side starts is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Use of auxiliary boiler steam to minimize steam-side starts
This operating technique can and will be used to minimize wear and tear on the equipment when frequent cycling is required, and when market conditions support auxiliary boiler firing to provide steam to the turbine seals and minimize thermal stress to enable rapid return to full firing the next

day, etc. This is a technique that favors the system's maintenance schedule and, when economically advantageous may represent a preferred operating strategy. However, such operation is not a technically feasible requirement or operating limitation to reduce emissions of NOx during startups and shutdowns because market conditions may not support such operation within the definition and purpose of the project – to provide clean, reliable and low cost power to our customers

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Use of auxiliary boiler steam to minimize steam-side starts is not a technically feasible option for the combined cycle combustion turbines (EU-1 and EU-2) at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only controls determined to be technically feasible and demonstrated in practice for the proposed combustion turbines to limit emissions of NOx during startup and shutdowns include operational techniques to minimize NOx emissions in terms of lb/event and total annual tons of NOx per year (rolling 12-months) achieved by managing, to the extent possible, the number, type and duration of startup events. The source proposes to employ all of these techniques, to the extent practicable, to limit per event and annual emissions of NOx from startups and shutdowns. These operational procedures are technically feasible only to the extent that they do not re-define the source being permitted. No other control alternatives have been identified as demonstrated in practice for any similar facility as capable of further reductions in NOx under transient startup and shutdown conditions. Vendor requirements were used to define the levels of mass emissions per event that represent the top level of NOx control which also reflects BACT and LAER during startup and shutdown of the proposed combined cycle combustion turbines.

Step 4: Evaluate the Most Effective Controls and Document the Results

This top level of control reflects the vendor data used to define the levels of mass emissions per event, and proposed restrictions on the total annual NOx emissions totalized for all estimated startup and shutdown events annually. Specifically, BACT for NOx during startup and shutdown events is proposed to be 429 pounds per event and 68 tons per 12-month rolling period for the two CCCT units combined. Compliance with these emission limitations from the combustion turbines during startup and shutdown events will be determined through Part 60 and 75 certified continuous emissions monitoring systems (CEMS).

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for NOx for the combined cycle combustion turbines:

The combined NOx emissions from the combined cycle combustion turbines stacks during startup and shutdown events is shall not exceed 429 pounds per event and 68 tons per twelve (12) consecutive month period.

Particulate Matter (PM and PM_{10}) BACT – Auxiliary Boiler EU-3

Emissions of PM and PM_{10} are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM and PM_{10} emissions are controlled through one of the following mechanisms:

(1) Fabric Filter Dust Collectors (Baghouses).

(2) Electrostatic Precipitators (ESP); and

(3) Wet Scrubbers;

(4) Cyclones or Multiclones;

(5) Fuel Specification; and

(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Fabric Filtration:
A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired boilers generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Baghouse is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Electrostatic Precipitators:
An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Electrostatic precipitator (ESP) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an electrostatic precipitator is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Wet scrubbers:
A wet scrubber is an air pollution control device that removes particulate matter from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulate matter. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulate matter size decreases. Collection efficiencies also vary with scrubber type.

Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulate matter with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles which are difficult to remove in their dry form;

(4) PM in the presence of soluble gases; and

(5) PM in waste gas streams with high moisture content.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they are limited to lower waste gas flow rates and temperatures than ESPs or baghouses. Current wet scrubber designs accommodate air flow rates over 100,000 actual cubic feet per minute and temperatures of up to 750°F. Lastly, downstream corrosion or plume visibility problems can result unless the added moisture is removed from the gas stream.

Gas temperatures are between 40 to 750 °F. The typical waste stream inlet flow is 500 - 100,000 scfm (units in parallel can operate at greater flow rates). Effluent wastewater stream may require treatment. Sludge disposal may be costly. Wet scrubbers are particularly susceptible to corrosion. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. A wet scrubber would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Cyclones:
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and Up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Fuel Specifications
Combusting only **c**lean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating PM and PM_{10} emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the Auxiliary Boilers to keep them in good working order per the manufacturer's specifications will minimize PM and PM_{10} emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM and PM_{10} resulting from the operation of the Auxiliary Boiler (EU-3).

(1) Fuel Specifications; and

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM and PM_{10} BACT determination along with the existing PM and PM_{10} BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Auxiliary Boiler (EU-3)**	**79.3 MMBtu/hr**	**PM and PM10: 0.005 lb/MMBtu and 0.4 lb/hr, each, based on 3-hr average**	**Good Combustion Practices and Fuel Specifications**
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Auxiliary Boilers (B001 and B002)	80 MMBtu/hr	PM/PM10/PM2.5: 0.0075 lb/MMBtu and 0.6 lb/hr, each, based on 3-hr average	Good Combustion Practices and Fuel Specifications
LA-0254	Entergy Louisiana, LLC, Ninemile Point Electric Generating Plant	08/16/2011	Natural gas-fired Auxiliary Boiler	3380 MMBtu/hr	$PM_{2.5}$ & PM_{10}: 7.6 lb/MMscf annual avg	None
OH-0310	American Municipal Power Generating Station	10/08/2009	Natural gas-fired Auxiliary Boiler	150 MMBtu/hr	PM_{10}: 1.14 lb/hr; 0.5 tpy; 7.6 lb/MMcf	None
LA-0231	Lake Charles Generation, LLC Lake Charles Gasification Facility	06/22/2009	Natural gas-fired Auxiliary Boiler	938.3 MMBtu/hr	PM_{10}: 6.99 lb/hr	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
AR-0094	Southwest Electric Power Plant Company, John W. Turk Power Plant	11/05/2008	Natural gas-fired Auxiliary Boiler	555 MMBtu/hr	0.0040 lb/MMBtu, 3-hr avg	None
PA-0257	Sunnyside Ethanol, LLC	05/07/2007	Natural gas-fired Auxiliary Boiler with diesel fuel capabilities	76,000 cf/hr	PM: 0.024 lb/MMBtu for natural gas	None
NY-0095	Caithness Bellport Energy Center	05/10/2006	Natural gas-fired Auxiliary Boiler	29.4 MMBtu/hr	PM_{10}: 0.0033 lb/MMBtu	None
OH-0407	Biomass Center, South Point Biomass Generation	0/04/2006	Natural gas-fired Auxiliary Boiler	247 MMBtu/hr	PM_{10}: 1.73 lb/hr; 3.26 tpy; 0.007 lb/MMBtu	None
OR-0046	Calpine Turner Energy Center, LLC	01/06/2005	Natural gas-fired Auxiliary Boiler	417,904 MMBtu/yr	PM_{10}: Use of natural gas is RACT	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station	12/01/2004	Natural gas-fired Auxiliary Boiler	38.0 MMBtu/hr	PM_{10}: 0.0033 lb/MMBtu	None
NV-0037	Sempra Energy Resources, Copper Mountain Power	05/14/2004	Natural gas-fired Auxiliary Boiler	60 MMBtu/hr	PM_{10}: 0.5 lb/hr; natural gas only (LAER)	None
WV-0023	Longview Power, LLC, Maidsville	03/02/2004	Natural gas-fired Auxiliary Boiler	225 MMBtu/hr	PM/PM_{10}: 0.0022 lb/MMBtu 6-hr rolling avg	None
OH-0269	Biomass Energy, LLC – South Point Power	01/05/2004	Natural gas- and fuel oil-fired Auxiliary Boiler	247 MMBtu/hr	PM_{10}: 1.73 lb/hr nat gas; 3.26 tpy nat gas & fuel oil; 0.007 lb/MMBtu nat gas	None

The source proposed a limit of 0.005 lb/MMBtu for the auxiliary boiler, which is consistent with the limit recently established by IDEM for St. Joseph Energy, a similar facility. There were four facilities identified in the RBLC that show more stringent emission limits than the proposed BACT limit, as further described below:

- Caithness Bellport Energy Center, New York: The RBLC identifies a BACT limit of 0.0033 lb/MMBtu. The facility's permit states that the limit is for PM_{10} and the referenced test methods are 201A & 202. This permit does not address $PM_{2.5}$. We believe that this limit is an outlier and there is insufficient information or operational experience for facilities such as this to support this limit.

- Dome Valley Energy Partners, Wellton Mohawk Generating Station, Arizona: The technical review on the EPA website does not include a limit for this facility but states "Good combustion practices, operating the equipment according to manufacturer specifications and the use of natural gas have been identified and accepted as BACT for CO, VOC, PM_{10}, and SO_2 ".

- Longview Power, LLC, Maidsville, West Virginia: The limit in the permit is for PM and PM_{10} emissions not for $PM_{2.5}$. The facility was permitted in 2004 and commercial operation was supposed to begin in 2011. There are no updates on the company's website since June 2011 so operation and verification of emission factors could not be confirmed.

The following has been proposed as BACT for PM and PM_{10} emissions from the proposed Auxiliary Boiler, identified as EU-3:

The PM and PM_{10} emissions from the Auxiliary Boiler, identified as EU-3 shall be limited to less than 0.005 lb/MMBtu and 0.4 lbs/hr, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for PM and PM_{10} for the Auxiliary Boiler (EU-3).

The PM and PM_{10} emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.005 lb/MMBtu and 0.4 lbs/hour, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Particulate Matter ($PM_{2.5}$) BACT – Auxiliary Boiler EU-3

Emissions of $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Fabric Filter Dust Collectors (Baghouses).

(2) Electrostatic Precipitators (ESP); and

(3) Wet Scrubbers;

(4) Cyclones or Multiclones;

(5) Fuel Specification; and

(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Fabric Filtration:
A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired boilers generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Baghouse is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Electrostatic Precipitators:
An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. An electrostatic precipitator (ESP) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an electrostatic precipitator is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Wet scrubbers:
A wet scrubber is an air pollution control device that removes particulate matter from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulate matter. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulate matter size decreases. Collection efficiencies also vary with scrubber type.

Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulate matter with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles which are difficult to remove in their dry form;

(4) PM in the presence of soluble gases; and

(5) PM in waste gas streams with high moisture content.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they are limited to lower waste gas flow rates and temperatures than ESPs or baghouses. Current wet scrubber designs accommodate air flow rates over 100,000 actual cubic feet per minute and temperatures of up to 750°F. Lastly, downstream corrosion or plume visibility problems can result unless the added moisture is removed from the gas stream.

Gas temperatures are between 40 to 750 °F. The typical waste stream inlet flow is 500 - 100,000 scfm (units in parallel can operate at greater flow rates). Effluent wastewater stream may require treatment. Sludge disposal may be costly. Wet scrubbers are particularly susceptible to corrosion. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. A wet scrubber would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Cyclones:
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and Up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Fuel Specifications
Combusting only **c**lean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating $PM_{2.5}$ emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the Auxiliary Boilers to keep them in good working order per the manufacturer's specifications will minimize PM, PM_{10} and $PM_{2.5}$ emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of $PM_{2.5}$ resulting from the operation of the Auxiliary Boiler (EU-3).

(1) Fuel Specifications; and

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM_{2.5}$ BACT determination along with the existing $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permit.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Auxiliary Boiler (EU-3)**	**79.3 MMBtu/hr**	**PM2.5: 0.005 lb/MMBtu and 0.4 lb/hr, each, based on 3-hr average**	**Good Combustion Practices and Fuel Specifications**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Auxiliary Boilers (B001 and B002)	80 MMBtu/hr	PM/PM10/PM2.5: 0.0075 lb/MMBtu and 0.6 lb/hr, each, based on 3-hr average	Good Combustion Practices and Fuel Specifications
OH-0310	American Municipal Power Generating Station	10/08/2009	Natural gas-fired Auxiliary Boiler	150 MMBtu/hr	PM_{10}: 1.14 lb/hr; 0.5 tpy; 7.6 lb/MMcf	None
PA-0257	Sunnyside Ethanol, LLC	05/07/2007	Natural gas-fired Auxiliary Boiler with diesel fuel capabilities	76,000 cf/hr	PM: 0.024 lb/MMBtu for natural gas	None
NY-0095	Caithness Bellport Energy Center	05/10/2006	Natural gas-fired Auxiliary Boiler	29.4 MMBtu/hr	PM_{10}: 0.0033 lb/MMBtu	None
OH-0407	Biomass Center, South Point Biomass Generation	0/04/2006	Natural gas-fired Auxiliary Boiler	247 MMBtu/hr	PM_{10}: 1.73 lb/hr; 3.26 tpy; 0.007 lb/MMBtu	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station	12/01/2004	Natural gas-fired Auxiliary Boiler	38.0 MMBtu/hr	PM_{10}: 0.0033 lb/MMBtu	None
NV-0037	Sempra Energy Resources, Copper Mountain Power	05/14/2004	Natural gas-fired Auxiliary Boiler	60 MMBtu/hr	PM_{10}: 0.5 lb/hr; natural gas only (LAER)	None
WV-0023	Longview Power, LLC, Maidsville	03/02/2004	Natural gas-fired Auxiliary Boiler	225 MMBtu/hr	PM/PM_{10}: 0.0022 lb/MMBtu 6-hr rolling avg	None
OH-0269	Biomass Energy, LLC – South Point	01/05/2004	Natural gas- and fuel oil-fired Auxiliary Boiler	247 MMBtu/hr	PM_{10}: 1.73 lb/hr nat gas; 3.26 tpy nat gas & fuel	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
	Power				oil; 0.007 lb/MMBtu nat gas	

The source proposed a limit of 0.005 lb/MMBtu for the auxiliary boiler, which is consistent with the limit recently established by IDEM for St. Joseph Energy that is a similar facility. There were four facilities identified in the RBLC that show more stringent emission limits than the proposed BACT limit, as further described below:

- Caithness Bellport Energy Center, New York: The RBLC identifies a BACT limit of 0.0033 lb/MMBtu. The facility's permit states that the limit is for PM_{10} and the referenced test methods are 201A & 202. This permit does not address $PM_{2.5}$. We believe that this limit is an outlier and there is insufficient information or operational experience for facilities such as this to support this limit.

- Dome Valley Energy Partners, Wellton Mohawk Generating Station, Arizona: The technical review on the EPA website does not include a limit for this facility but states "Good combustion practices, operating the equipment according to manufacturer specifications and the use of natural gas have been identified and accepted as BACT for CO, VOC, PM_{10}, and SO_2 ".

- Longview Power, LLC, Maidsville, West Virginia: The limit in the permit is for PM and PM_{10} emissions not for $PM_{2.5}$. The facility was permitted in 2004 and commercial operation was supposed to begin in 2011. There are no updates on the company's website since June 2011 so operation and verification of emission factors could not be confirmed.

  The following has been proposed as BACT for $PM_{2.5}$ emissions from the proposed Auxiliary Boiler, identified as EU-3:

  The $PM_{2.5}$ emissions from the Auxiliary Boiler, identified as EU-3 shall be limited to less than 0.005 lb/MMBtu and 0.4 lbs/hr, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for $PM_{2.5}$ for the Auxiliary Boiler (EU-3).

The $PM_{2.5}$ emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.005 lb/MMBtu and 0.4 lbs/hour, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Sulfuric Acid (H_2SO_4) BACT – Auxiliary Boiler EU-3

Step 1: Identify Potential Control Technologies

Emissions of Sulfuric Acid (H_2SO_4) emissions depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. Sulfuric Acid (H_2SO_4) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Flue Gas Desulfurization (FGD) System);

(2) Dry Sorbent Injection; and

(3) Fuel Specification.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. H_2SO_4 emissions are not dependent upon combustion properties such as size or burner design.

Step 2: Eliminate Technically Infeasible Options

Flue Gas Desulfurization (FGD) System
A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. FGD typically operates at a temperature of approximately 300°F to 700°F (wet) and 300°F to 1830°F (dry). The FGD has a waste stream inlet pollutant concentration of 2,000 ppmv. Absorption of SO_2 is accomplished by the contact between the exhaust and an alkaline reagent, which results in the formation of neutral salts. Wet systems employ reagents using packed or spray towers and generate wastewater streams, while dry systems inject slurry reagent into the exhaust stream to react, dry and be removed downstream by particulate control equipment. By removing SO_2 from the exhaust stream, conversion of SO_2 to SO_3 and H_2SO_4 is reduced. Chlorine emissions can result in salt deposition within the absorber and in downstream equipment. Wet systems may require flue gas re-heating downstream of the absorber to prevent corrosive condensation. Inlet streams for dry systems must be cooled as appropriate, and dry systems require use of particulate controls to collect the solid netural salts.

FGD systems are not listed in the RBLC as BACT for the control of H_2SO_4 emissions for large combined cycle combustion turbines. Technology has not been applied to natural gas combined cycle combustion turbines due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of flue gas desulfurization system (FGD) is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Dry Sorbent Injection
A post-combustion technology in which a calcium or sodium-based sorbent reacts with SO_2 and SO_3 and is removed downstream by particulate control equipment. The reduced availability of SO_2 and SO_3 in the exhaust stream reduces H_2SO_4 formation, thereby reducing H_2SO_4 emissions. The system requires use of particulate controls to collect the reaction solids. Technology has not been applied to natural gas combined cycle combustion turbines due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction. Dry sorbent injection is not listed in the RBLC as BACT for the control of H_2SO_4 emissions for large combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of dry sorbent injection is not a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating H_2SO_4 emissions. Fuel Specifications is included in RBLC for the control of H_2SO_4 from Auxiliary Boiler.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Auxiliary Boiler (EU-3) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of H_2SO_4 resulting from the operation of the Auxiliary Boiler (EU-3).

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed H_2SO_4 BACT determination along with the existing H_2SO_4 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Auxiliary Boiler (EU-3)**	**79.3 MMBtu/hr, each**	**H_2SO_4: 0.75 gr S/100 scf natural gas**	**Fuel Specification**
FL-0330	Port Dolphin Energy, LLC	12/01/2011	Natural gas-fired Boilers	NA	0.34 lb/hr, 3-hr rolling average	None
OH-0317	Ohio River Clean Fuels, LLC	11/20/2008	Natural gas- and tail gas-fired Boiler	1,200 MMBtu/hr	0.17 lb/hr, 3-hr average; 0.75 tpy per rolling 12-month period	None
MD-0040	Competitive Power Ventures, Inc. CPB St. Charles	11/12/2008	Natural gas-fired Auxiliary Boiler	93 MMBtu/hr	0.0001 lb/mmbtu 3-hr avg	None
OR-0046	Calpine Turner Energy, LLC	01/06/2005	Natural gas-fired Auxiliary Boiler	417,904 MMBtu/hr	Use of natural gas is RACT	None
WI-0228	Wisconsin Public Service, Weston Plant	10/19/2004	Natural gas-fired Auxiliary Boiler	229.80 MMBtu/hr	0.210 lb/hr; 2,000 hrs/ 12 month rolling limit	None
TX-0386	Calpine Construction Amella Energy Center	03/26/2002	Natural gas-fired Auxiliary Boiler	155 MMBtu/hr	0.129 lb/hr	None

The RBLC was reviewed and a summary of the BACT determinations from auxiliary boilers is shown in above table. It should be noted that there were no facilities identified that utilized any add-on control technologies to reduce H_2SO_4 emissions from auxiliary boilers fired with natural gas. These emissions are characterized by variability in the sulfur content of pipeline natural gas which varies from pipeline to pipeline, and month to month, and is outside the direct control of the facility that receives its natural gas from the pipeline.

There are no technically feasible control technologies that have been identified that are capable of reducing or controlling emissions of H_2SO_4 from small natural gas-fired industrial boilers. The top level of control would be that emission rate that results from the limitation to utilize pipeline quality natural gas. Variations in this value are believed to occur simply based on the level of risk that previous applicants have agreed to accept and/or variations in natural gas sulfur content from pipeline to pipeline. While the RBLC does not identify any facilities that have determined BACT to be the use of pipeline natural gas, we believe that the use of pipeline quality natural gas will be the most effective means of reducing H_2SO_4 emissions.

The following has been proposed as BACT for H_2SO_4 emissions from the proposed auxiliary boiler, identified as EU-3:

(a) The H_2SO_4 emissions from the auxiliary boiler, identified as EU-3 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for H_2SO_4 for the auxiliary boiler, identified as EU-3.

(a) The H_2SO_4 emissions from the auxiliary boiler, identified as EU-3 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

Carbon Monoxide (CO) BACT – Auxiliary Boiler EU-3

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer

(c) Catalytic oxidation;

(d) Good Combustion Controls via Advance Ultra-Low NOx Burner; and

(e) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the waste gas containing CO is heated. The mixture continues to react as it flows through the combustion chamber. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

The required level of CO destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.
A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the Auxiliary Boiler at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Auxiliary Boiler at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. .

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Auxiliary Boiler at this source.

Flare
Although the CO concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Auxiliary Boiler at this source

Good Combustion Controls via Advance Ultra-Low NOx Burner
Good combustion controls is a continued operation of the auxiliary boiler at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation. Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion.

CO is formed in a package boiler as a trade-off with NO_x control in an ultra-low NO_x burner. The latest generation of low NO_x burners seeks to optimize emissions of NO_x and CO simultaneously. CO is minimized in boiler through good combustion practices, including low- NO_x burners, flue gas recirculation (FGR), and ultra-low- NO_x burners that each support effective combustion that minimizes CO generation.

Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.
Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the Auxiliary Boiler at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - (75% destruction efficiency)

(2) Combustion Control via Advance Ultra-low NOx burner

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permit.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Auxiliary Boiler (EU-3)**	**79.3 MMBtu/hr**	**CO: 0.082 lb/MMBtu and 6.5 lb/hr, based on 3-hr average**	**Combustion Control via Advance ultra-low NOx Burners**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Auxiliary Boilers (B001 and B002)	80 MMBtu/hr	CO: 0.083 lb/MMBtu and 6.64 lb/hr, each, based on 3-hr average	Good Combustion Practices
OH-0310	American Municipal Power Generating Station	10/08/2009	Natural gas-fired Auxiliary Boiler	150 MMBtu/hr	12.6 lb/hr; 5.52 tpy; 400 ppm by vol, dry basis to 3% O_2, 3-hr avg	None
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant	01/23/2009	Natural gas-fired Auxiliary Boiler	33.5 MMBtu/hr	5.02 lb/hr	None
WY-0064	Basin Electric Power Cooperative, Dry Fork Station	10/15/2007	Natural gas-fired Auxiliary Boiler	134 MMBtu/hr	0.08 lb/ MMBtu; 10.7 tpy, limited to 2,000 hrs of operation/year	None
FL-0285	Progress Energy Florida, Progress Bartow Power Plant	01/26/2007	Natural gas-fired Auxiliary Boiler	99 MMBtu/hr	0.08 lb/ MMBtu, 400 ppmvd	None
FL-0286	Florida Power & Light Co., FPL West County Energy Center	01/10/2007	Natural gas-fired Auxiliary Boiler	99.8 MMbtu/hr	0.08 lb/MMBtu	None
NY-0095	Caithness Bellport Energy Center	05/10/2006	Natural gas-fired Auxiliary Boiler	29.4 MMBtu/hr	0.036 lb/MMBtu	None
OH-0407	Biomass Center, South Point Biomass Generation	0/04/2006	Natural gas-fired Auxiliary Boiler	247 MMBtu/hr	27.17 lb/hr; 48.32 tpy; 0.11 lb/MMBtu	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station	12/01/2004	Natural gas-fired Auxiliary Boiler	38.0 MMBtu/hr	0.08 lb/MMBtu	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
NV-0037	Sempra Energy Resources, Copper Mountain Power	05/14/2004	Natural gas-fired Auxiliary Boiler	60 MMBtu/hr	0.08 lb/MMBtu; 4.8 lb/hr (LAER)	None
WV-0023	Longview Power, LLC, Maidsville	03/02/2004	Natural gas-fired Auxiliary Boiler	225 MMBtu/hr	0.04 lb/MMBtu 3-hour rolling avg	None
OH-0269	Biomass Energy, LLC – South Point Power	01/05/2004	Natural gas- and fuel oil-fired Auxiliary Boiler	247 MMBtu/hr	27.17 lb/hr nat gas; 48.23 tpy nat gas & fuel oil; 0.011 lb/MMBtu nat gas	None

There were four facilities identified in the RBLC that show more stringent emission limits than the proposed BACT limit, as further described below:

- Caithness Bellport Energy Center, New York: The RBLC identifies a BACT limit of 0.036 lb/MMBtu. Again, we believe this limit is an outlier and there is insufficient information available to support such a limit as being achievable on an ongoing basis.

- Longview Power, LLC, Maidsville, West Virginia: The permit has a limit of 0.04 lbs/MMBtu for PM and PM_{10} emissions. The facility was permitted in 2004 and commercial operation was supposed to begin in 2011. There are no updates on the company's website since June 2011 so operation and verification of emission factors could not be confirmed.

- Biomass Center, South Point Biomass Generation, Ohio: The RBLC shows a limit of 27.17 lb/hr, and indicates a basis of 0.11 lbs/MMBtu and not 0.011 lbs/MMBtu as shown in RBLC table. As such IDEM believe that the CO limit for this facility is not more stringent than that that proposed by IPL.

Cost Analysis for Regenerative Incinerators
The cost of add-on control technology to control CO emissions is not cost effective due to the low concentration of CO in the exhaust stream. The U.S. EPA's Air Pollution Control Technology Fact Sheet for Regenerative Incinerators (EPA-452/F-03-021) provides annualized costs ranging from $8 to $33/cfm for regenerative thermal oxidizers and $11 to $41/cfm for catalytic oxidizers. The auxiliary boiler has a design exhaust flow rate of approximately 24,500 cfm, but a low maximum potential CO emission rate (28.5 tpy based on 8,760 hours per yr at full load), and using a conservative cost of $8/cfm, the cost effectiveness of installing add-on controls would be at least $56,000/ton of CO removed. Under expected operating conditions (500 hours/yr), the cost effectiveness would be more than $560,000 ton controlled. As such, neither regenerative thermal oxidation nor thermal oxidation could possibly be considered to be cost effective.

The following has been proposed as BACT for CO emissions from the proposed Auxiliary Boiler, identified as EU-3:

The CO emissions from the Auxiliary Boiler (EU-3) operation shall not exceed 0.082 lb/MMBtu and 6.65 lbs/hr, each, based on a 3 - hour average through the use of advanced ultra -low NOx burner.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for CO for Auxiliary Boilers (EU-3).

The CO emissions from the Auxiliary Boiler (EU-3) operation shall not exceed 0.083 lb/MMBtu and 6.65 lbs/hr, each, based on a 3 - hour average through the use of advanced ultra -low NOx burner.

Volatile Organic Compounds (VOCs) BACT - Auxiliary Boiler EU-3

Step 1: Identify Potential Control Technologies

Emissions of Volatile Organic Compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer

(c) Catalytic oxidation;

(d) Good Combustion Controls via Advance Ultra-Low NOx Burner; and

(e) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling VOCs emissions. Upon passing through the flame, the waste gas containing VOCs is heated. The mixture continues to react as it flows through the combustion chamber. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

The required level of VOCs destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is a technically feasible option for the Auxiliary Boiler at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Auxiliary Boiler at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOCs emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Auxiliary Boilers at this source.

Flare
Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for VOCs from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Auxiliary Boiler at this source

Good Combustion Controls via Advance Ultra-Low NOx Burner
Good combustion controls is a continued operation of the boiler at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion.

VOC is formed in a package boiler as a trade-off with NOx control in an ultra-low NOx burner. The latest generation of low NOx burners seeks to optimize emissions of NOx and CO simultaneously. VOC is minimized in boiler through good combustion practices, including low-NOx burners, flue gas recirculation (FGR), and ultra-low- NO_x burners that each support effective combustion that minimizes VOC generation.

Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the Auxiliary Boiler at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - (75% destruction efficiency)

(2) Combustion Control via Ultra-low NOx burner

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOCs BACT determination along with the existing VOCs BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permit.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Auxiliary Boiler (EU-3)**	**79.3 MMBtu/hr**	**VOCs: 0.0053 lb/MMBtu and 0.42 lb/hr, based on 3-hr average**	**Advance ultra-low NOx Burners**
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Auxiliary Boilers (B001 and B002)	80 MMBtu/hr	VOCs: 0.005 lb/MMBtu and 0.4 lb/hr, each, based on 3-hr average	Good Combustion Practices
OH-0310	American Municipal Power Generating Station	10/08/2009	Natural gas-fired Auxiliary Boiler	150 MMBtu/hr	0.83 lb/hr; 0.36 tpy; 5.5 lb/MMscf	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant	01/23/2009	Natural gas-fired Auxiliary Boiler	33.5 MMBtu/hr	0.54 lb/hr	None
PA-0257	Sunnyside Ethanol, LLC	05/07/2007	Natural gas-fired Auxiliary Boiler with diesel fuel capabilities	76,000 cf/hr	0.014 lb/MMBtu for natural gas	None
OH-0407	Biomass Center, South Point Biomass Generation	0/04/2006	Natural gas-fired Auxiliary Boiler	247 MMBtu/hr	0.99 lb/hr; 1.76 tpy; 0.004 lb/MMBtu	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station	12/01/2004	Natural gas-fired Auxiliary Boiler	38.0 MMBtu/hr	0.0033 lb/MMBtu	None
NV-0037	Sempra Energy Resources, Copper Mountain Power	05/14/2004	Natural gas-fired Auxiliary Boiler	60 MMBtu/hr	0.40 lb/hr (LAER)	None
WV-0023	Longview Power, LLC, Maidsville	03/02/2004	Natural gas-fired Auxiliary Boiler	225 MMBtu/hr	0.0054 lb/MMBtu 3-hr rolling avg	None
OH-0269	Biomass Energy, LLC – South Point Power	01/05/2004	Natural gas- and fuel oil-fired Auxiliary Boiler	247 MMBtu/hr	0.99 lb/hr nat gas; 1.76 tpy nat gas & fuel oil	None

There were three facilities identified in the RBLC that show more stringent emission limits than the proposed BACT limit, as further described below:

- Calpine Turner Energy Center, Oregon: This facility was not built.
- Biomass Center, South Point Biomass Generation, Ohio: A review of the Title V permit shows that this limit was not included in the permit. The permit includes a limit of 0.99 lbs VOC/hr (as shown in IPL's BACT submittal), but does not include a lbs/mmbtu value.
- Dome Valley Energy Partners, Wellton Mohawk Generating Station, Arizona: The final permit could not be obtained. The Technical Review on the EPA website does not include a limit for this facility but states "Good combustion practices, operating the equipment according to manufacturer specifications and the use of natural gas have been identified and accepted as BACT for CO, VOC, PM_{10}, and SO_2."

Cost Analysis for Regenerative Incinerators
The cost of add-on control technology to control VOC emissions is not cost effective due to the low concentration of VOC in the exhaust stream. The U.S. EPA's Air Pollution Control Technology Fact Sheet for Regenerative Incinerators (EPA-452/F-03-021) provides annualized costs ranging from $8 to $33/cfm for regenerative thermal oxidizers and $11 to $41/cfm for catalytic oxidizers. The auxiliary boiler has a design exhaust flow rate of approximately 24,500 cfm, but a low maximum potential VOC emission rate (28.5 tpy based on 8,760 hours per yr at full load), and using a conservative cost of $8/cfm, the cost effectiveness of installing add-on controls would be at least $56,000/ton of VOC removed. Under expected operating conditions (500 hours /yr, the cost effectiveness would be more than $560,000 ton controlled. As such, neither regenerative thermal oxidation nor thermal oxidation could possibly be considered to be cost effective.

The following has been proposed as BACT for VOC emissions from the proposed Auxiliary Boiler (EU-3):

The VOC emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.42 lbs/hr, each, based on a 3-hr average period through the use of advanced ultra -low NOx burner.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for VOC for the Auxiliary Boiler (EU-3).

The VOC emissions from the Auxiliary Boiler, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.42 lbs/hr, each, based on a 3-hr average period through the use of advanced ultra - low NOx burner.

Nitrogen Oxide (NOx) BACT - Auxiliary Boiler EU-3

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR);

(b) Selective Non-Catalytic Reduction (SNCR);

(c) SCONOx Catalytic Absorption System; and

(d) Ultra-Low NOx Burners (LNB).

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750 F. Temperature below the optimum, decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a sootblower.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is a technically feasible option for the Auxiliary Boilers at this source.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2100°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water.
This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction. At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of a competing reaction for the direct oxidation of ammonia that actually forms NO_x becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the source exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is a technically feasible option for the Auxiliary Boilers at this source.

Low NOx Burner (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and fuel, as well as other methods that effectively lower the flame temperature. In the drive to reduce NOx emissions, NOx reduction techniques were implemented to lower peak flame temperature.

The ULNBs are specially designed pieces of combustion equipment that reduce NOx formation through careful control of the fuel-air mixture during combustion. In a staged air combustion LNB, either air or fuel is added downstream of the primary combustion zone. Depending on which of these NOx reduction techniques is used, LNBs with staged combustion are subdivided into staged air burners and staged fuel burners.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one burner installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible especially when another NOx reduction technique is used in conjunction with LNBs.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of low NOx burners is a technically feasible option for the Auxiliary Boilers at this source.

SCONOx Catalytic Absorption System

SCONOx Catalytic Absorption System utilizes a single catalyst to remove NO_X, CO, and VOC through oxidation. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. The Operating Temperature ranges from 300 - 700 °F. The $SCONO_X$ Catalyst is sensitive to contamination by sulfur, so it must be used in conjunction with the $SCOSO_X$ catalyst, which favors sulfur compound absorption. This technology has only been demonstrated on units ranging from 5 to 45 MW.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective SCONOx Catalytic Absorption System is not a technically feasible option for the Auxiliary Boilers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Selective Catalytic Reduction — (50-90% NOx Reduction)

(2) Selective Non-catalytic Reduction — (40-60% NOx Reduction)

(3) Low NOx Burner (LNB) — (40%-50% NOx Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permit.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Auxiliary Boiler (EU-3)**	**79.3 MMBtu/hr**	**NOx: 0.011 lb/MMBtu and 0.87 pounds per hour, based on 3-hr average**	**Low NOx Burner with Flue Gas Recirculation**
Draft Permit No. 141-31003-00579 Proposed Limit	St. Joseph Energy Center - *proposed*	12/03/2012	Auxiliary Boilers (B001 and B002)	80 MMBtu/hr	NOx: 0.032 lb/MMBtu and 2.56 pounds per hour, each, based on 3-hr average	Low NOx Burner with Flue Gas Recirculation
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant	01/23/2009	Natural gas-fired Auxiliary Boiler	33.5 MMBtu/hr	0.07 lb/MMBtu; 2.36 lb/hr	Low-NO_x burners
WY-0064	Basin Electric Power Cooperative, Dry Fork	10/15/2007	Natural gas-fired Auxiliary Boiler	134 MMBtu/hr	0.04 lb/MMBtu; 5.4 tpy, limited to 2,000 hrs of	Low-NO_x burners with flue gas recirculation

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
	Station				operation/year	
PA-0257	Sunnyside Ethanol, LLC	05/07/2007	Natural gas-fired Auxiliary Boiler with diesel fuel capabilities	76,000 cf/hr	0.035 lb/MMBtu for natural gas	Low-NO_x burners with flue gas recirculation
OH-0309	Daimler Chrysler Toledo Supplier Park-Paint Shop	05/03/2007	Natural gas-fired boilers	20.40 MMBtu/hr	0.035 lb/MMBtu; 7.2 lb/hr; 3.5 tpy (LAER)	Low-NO_x burners with flue gas recirculation
FL-0286	Florida Power & Light Co., FPL West County Energy Center	01/10/2007	Natural gas-fired Auxiliary Boiler	99.8 MMbtu/hr	0.05 lb/MMBtu	None
OK-0115	Energetix Lawton Energy Cogen Facility	12/12/2006	Natural gas-fired Auxiliary Boiler	NA	0.036 lb/MMBtu	Dry-Low NO_x burners
NY-0095	Caithness Bellport Energy Center	05/10/2006	Natural gas-fired Auxiliary Boiler	29.4 MMBtu/hr	0.0110 lb/MMBtu	Low NO_x - burners and FGR
OH-0407	Biomass Center, South Point Biomass Generation	0/04/2006	Natural gas-fired Auxiliary Boiler	247 MMBtu/hr	14.82 lb/hr; 27.02 tpy; 0.06 lb/MMBtu	None
AZ-0047	Dome Valley Energy Partners, Wellton Mohawk Generating Station	12/01/2004	Natural gas-fired Auxiliary Boiler	38.0 MMBtu/hr	0.37 lb/ MMBtu	Low NO_x - burners
NV-0037	Sempra Energy Resources, Copper Mountain Power	05/14/2004	Natural gas-fired Auxiliary Boiler	60 MMBtu/hr	0.035 lb/ MMBtu; 9.6 tpy	Low NO_x burners with either internal or external FGR
WV-0023	Longview Power, LLC, Maidsville	03/02/2004	Natural gas-fired Auxiliary Boiler	225 MMBtu/hr	0.098 lb/ MMBtu	Low NO_x - burners
OH-0269	Biomass Energy, LLC – South Point Power	01/05/2004	Natural gas- and fuel oil-fired Auxiliary Boiler	247 MMBtu/hr	14.82 lb/hr nat gas; 27.02 tpy nat gas & fuel oil; 0.06 lb/ MMBtu nat gas	None

Ultra-low-NOx burners have been proven to reduce NOx emissions to 0.011 lb/MMBtu, which has been determined to be the top level of control for small natural gas-fired auxiliary boilers used to back up combined cycle power plants.

Ultra-Low NOx burners employ internal or external flue gas recirculation (FGR). FGR reduces NOx emissions in industrial boilers by recirculating a portion of the exhaust gas back into the combustion process. This results in lower combustion temperatures and oxygen levels in the combustion air/flue gas mixture, thus retarding the formation of thermal NOx. More traditional burners operate with less combustion staging and less overall pressure drop.

The following has been proposed as BACT for NOx emissions from the proposed Auxiliary Boiler, identified as EU-3:

(1) The NOx emissions from the Auxiliary Boilers, identified as EU-3 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(2) The NOx emissions shall be limited to less than 0.011 lb/MMBtu pounds per hour, based on a 3-hr average period.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for NOx for the Auxiliary Boilers, identified as EU-3:

(1) The NOx emissions from the Auxiliary Boilers, identified as EU-3 shall be controlled by Low NOx Burners with Flue Gas Recirculation.

(2) The NOx emissions shall be limited to less than 0.011 lb/MMBtu and 0.87 pounds per hour, based on a 3-hr average period.

Particulate Matter (PM and PM_{10}) BACT – Dew Point heater EU-4

Emissions of PM and PM_{10} are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM and PM_{10} emissions are controlled through one of the following mechanisms:

(1) Fabric Filter Dust Collectors (Baghouses).

(2) Electrostatic Precipitators (ESP); and

(3) Wet Scrubbers;

(4) Cyclones or Multiclones;

(5) Fuel Specification; and

(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Fabric Filtration:
A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired boilers generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Baghouse is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Electrostatic Precipitators:
An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. An electrostatic precipitator (ESP) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an electrostatic precipitator is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Wet scrubbers:
A wet scrubber is an air pollution control device that removes particulate matter from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulate matter. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulate matter size decreases. Collection efficiencies also vary with scrubber type.

Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulate matter with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles which are difficult to remove in their dry form;

(4) PM in the presence of soluble gases; and

(5) PM in waste gas streams with high moisture content.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they are limited to lower waste gas flow rates and temperatures than ESPs or baghouses. Current wet scrubber designs accommodate air flow rates over 100,000 actual cubic feet per minute and temperatures of up to 750°F. Another disadvantage is that they generate waste in the form of a sludge which requires treatment and/or disposal. Lastly, downstream corrosion or plume visibility problems can result unless the added moisture is removed from the gas stream.

Gas temperatures are between 40 to 750 °F. The typical waste stream inlet flow is 500 - 100,000 scfm (units in parallel can operate at greater flow rates). Effluent wastewater stream may require treatment. Sludge disposal may be costly. Wet scrubbers are particularly susceptible to corrosion. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. A wet scrubber would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Cyclones:
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and Up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Fuel Specifications
Combusting only **c**lean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating PM and PM_{10} emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Dew Point Heater (EU-4) at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the Dew Point Heater to keep them in good working order per the manufacturer's specifications will minimize PM and PM_{10} emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Dew Point Heater (EU-4) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM and PM_{10} resulting from the operation of the Dew Point Heater (EU-4).

(1) Fuel Specifications; and

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM and PM_{10} BACT determination along with the existing PM and PM_{10} BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permit.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Dew Point Heater (EU-4)**	**20.8 MMBtu/hr**	**PM and PM10: 0.0072 lb/MMBtu and 0.15 lb/hr, each, based on 3-hr average**	**Good Combustion Practices and Fuel Specifications**
AK-0071	Chugach Electric Association, Inc., International Station Power Plant	12/20/2010	Sigma Thermal Auxiliary Heater	12.5 MMBtu/hr	$PM/PM_{10}/PM_{2.5}$: 7.6 lb/mmscf, 3-hr avg	None
IA-0064	Roquette America	01/31/2003	Dew Point Heater	1.6 MMBtu/hr	PM: 0.008 lb/mmbtu; 0.120 lb/hr	None

As shown in the above table, a limit of 0.0072 lb/MMBtu which is the most stringent is consistent with the other limits contained in the RBLC.

The following has been proposed as BACT for PM and PM_{10} emissions from the proposed Dew Point Heater, identified as EU-4:

The PM and PM_{10} emissions from the Dew Point Heater, identified as EU-4 shall be limited to less than 0.0072 lb/MMBtu and 0.15 lbs/hr, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for PM and PM_{10} for the Dew Point Heater (EU-4).

The PM and PM_{10} emissions from the Dew Point Heater, identified as EU-4 shall be limited to less than 0.0072 lb/MMBtu and 0.15 lbs/hr, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Particulate Matter ($PM_{2.5}$) BACT – Dew Point heater EU-4

Emissions of $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Fabric Filter Dust Collectors (Baghouses).

(2) Electrostatic Precipitators (ESP); and

(3) Wet Scrubbers;

(4) Cyclones or Multiclones;

(5) Fuel Specification; and

(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Fabric Filtration:
A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired boilers generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Baghouse is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Electrostatic Precipitators:
An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. An electrostatic precipitator (ESP) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a electrostatic precipitator is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Wet scrubbers:
A wet scrubber is an air pollution control device that removes particulate matter from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulate matter. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulate matter size decreases. Collection efficiencies also vary with scrubber type.

Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulate matter with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles which are difficult to remove in their dry form;

(4) PM in the presence of soluble gases; and

(5) PM in waste gas streams with high moisture content.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they are limited to lower waste gas flow rates and temperatures than ESPs or baghouses. Current wet scrubber designs accommodate air flow rates over 100,000 actual cubic feet per minute and temperatures of up to 750°F. Lastly, downstream corrosion or plume visibility problems can result unless the added moisture is removed from the gas stream.

Gas temperatures are between 40 to 750 °F. The typical waste stream inlet flow is 500 - 100,000 scfm (units in parallel can operate at greater flow rates). Effluent wastewater stream may require treatment. Sludge disposal may be costly. Wet scrubbers are particularly susceptible to corrosion. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. A wet scrubber would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Cyclones:
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and Up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural-gas fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the Dew Point Heater (EU-4) at this source.

Fuel Specifications
Combusting only **c**lean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating $PM_{2.5}$ emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Dew Point Heater (EU-4) at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the Dew Point Heater to keep them in good working order per the manufacturer's specifications will minimize $PM_{2.5}$ emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Dew Point Heater (EU-4) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of $PM_{2.5}$ resulting from the operation of the Dew Point Heater (EU-4).

(1) Fuel Specifications; and

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM_{2.5}$ BACT determination along with the existing $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Dew Point Heater (EU-4)**	**20.8 MMBtu/hr**	**PM2.5: 0.0072 lb/MMBtu and 0.15 lb/hr, each, based on 3-hr average**	**Good Combustion Practices and Fuel Specifications**
AK-0071	Chugach Electric Association, Inc., International Station Power Plant	12/20/2010	Sigma Thermal Auxiliary Heater	12.5 MMBtu/hr	$PM/PM_{10}/PM_{2.5}$: 7.6 lb/mmscf, 3-hr avg	None
IA-0064	Roquette America	01/31/2003	Dew Point Heater	1.6 MMBtu/hr	PM: 0.008 lb/MMBtu; 0.120 lb/hr	None

As shown in the above table, a limit of 0.0072 lb/MMBtu which is the most stringent is consistent with the other limits contained in the RBLC.

The following has been proposed as BACT for $PM_{2.5}$ emissions from the proposed Dew Point Heater, identified as EU-4:

The $PM_{2.5}$ emissions from the Dew Point Heater, identified as EU-4 shall be limited to less than 0.072 lb/MMBtu and 0.15 lbs per hour, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for $PM_{2.5}$ for the Dew Point Heater (EU-4).

The $PM_{2.5}$ emissions from the Dew Point Heater, identified as EU-4 shall be limited to less than 0.0072 lb/MMBtu and 0.15 lbs/hr, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Sulfuric Acid (H_2SO_4) BACT – Dew Point Heater EU-4

Step 1: Identify Potential Control Technologies

Emissions of Sulfuric Acid (H_2SO_4) emissions depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. Sulfuric Acid (H_2SO_4) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Flue Gas Desulfurization (FGD) System);

(2) Dry Sorbent Injection; and

(3) Fuel Specification.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. H_2SO_4 emissions are not dependent upon combustion turbine properties such as size or burner design.

Step 2: Eliminate Technically Infeasible Options

Add-on Control Technology
Add-on particulate control devices such as Flue Gas Desulfurization (FGD) System, Dry Sorbent Injection are not possible alternatives because the potential H_2SO_4 emissions from emergency engines are very minor, given their limited hours of operation. With such insignificant emissions, it would not be considered feasible to employ add-on control technologies to reduce H_2SO_4emissions from emergency engines. Additionally, since control technologies have not been implemented in practice to control emissions from emergency engines, there is no evidence that such measures would be technically feasible.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating H_2SO_4 emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Dew Point Heater (EU-4) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of H_2SO_4 resulting from the operation of the Dew Point Heater (EU-4).

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

There are no technically feasible control technologies that have been identified that are capable of reducing or controlling emissions of H_2SO_4 from small natural gas-fired heaters. The top level of control would be that emission rate that results from the limitation to utilize pipeline quality natural gas. Variations in this value are believed to occur simply based on the level of risk that previous applicants have agreed to accept and/or variations in natural gas sulfur content from pipeline to pipeline. While the RBLC does not identify any facilities that have determined BACT to be the use of pipeline natural gas, the use of pipeline quality natural gas will be the most effective means of reducing H_2SO_4 emissions.

The following has been proposed as BACT for H_2SO_4 emissions from the proposed dew point heater, identified as EU-4:

(a) The H_2SO_4 emissions from the dew point heater, identified as EU-4 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for H_2SO_4 for the dew point heater (EU-4).

(a) The H_2SO_4 emissions from the dew point heater, identified as EU-4 shall be limited by limiting the S content of the natural gas to 0.75 gr S/100 scf on a monthly average basis.

Carbon Monoxide (CO) BACT – Dew Point Heater EU-4

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer

(c) Catalytic oxidation;

(d) Good Combustion Controls; and

(e) Flares.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling VOC emissions. Upon passing through the flame, the waste gas containing CO is heated. The mixture continues to react as it flows through the

combustion chamber. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

The required level of CO destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the Dew Point Heater at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Dew Point Heater at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. .
Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Dew Point Heater at this source.

Flare
Although the CO concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Dew Point Heater at this source

Good Combustion Controls
Good combustion controls is a continued operation of the CCCT at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation. Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the Dew Point Heater at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - (75% destruction efficiency)

(2) Combustion Control via good combustion design and low NOx burners

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permit.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Dew Point Heater (EU-4)**	**20.8 MMBtu/hr**	**CO: 0.082 lb/MMBtu and 1.7 lb/hr, based on 3-hr average**	**Good Combustion Design and low NOx Burners**
WY-0070	Black Hills Power, Inc., Cheyenne Prairie Generating Station	08/28/2012	Inlet Air Heaters	16.10 MMBtu/hr (each)	0.08 lb/MMBtu, 3-hr avg; 1.3 lb/hr, 3-hr avg	None
WY-0066	Medicine Bow Fuel & Power	03/04/2009	Gasification Preheaters (5)	21 MMBtu/hr, each	0.08 lb/ MMBtu	None
IA-0058	Midamerican Energy, Greater Des Moines Energy Center	04/10/2002	Dew Point Heater	10 MMBtu/hr	0.036 lb/ MMBtu; 1.47 tpy	None
FL-0303	Florida Power & Light Co.	07/30/2008	Process Heaters	10 MMBtu/hr	0.08 lb/ MMBtu	None

The Midamerican Energy, Greater Des Moines Energy Center permit, issued on April 10, 2002 operates a 10 MMBtu/hr heater, without controls, and has a CO limit of 0.036 lb/MMBtu and 1.47 tpy. This emission limit is an outlier. The heater is small compare in size with the IPL dew point heater and IPL's proposed CO emission limit of 0.082 MMBtu/hour which is consistent with the AP-42 emission factor for mid-size heaters. Additionally, there is a preponderance of BACT determinations for small natural gas-fired heaters in the past few years that are consistent with the BACT determination for IPL of 0.082 lb/MMBtu.

The cost of add-on control technology to control CO emissions is not cost effective due to the low concentration of CO in the exhaust stream. The U.S. EPA's Air Pollution Control Technology Fact Sheet for Regenerative Incinerators (EPA-452/F-03-021) provides annualized costs ranging from $8 to $33/cfm for regenerative thermal oxidizers and $11 to $41/cfm for catalytic oxidizers. The dew point heater has a design exhaust flow rate of approximately 6,400 cfm, and a low maximum potential CO emission rate (7.5 tpy based on 8,760 hours per year at full load). Using a conservative cost of $8/cfm, the cost effectiveness of installing add-on controls would be at least $38,000 per ton of CO removed.

The following has been proposed as BACT for CO emissions from the proposed Dew Point Heater, identified as EU-4:

The CO emissions from the Dew Point Heater (EU-4) operation shall not exceed 0.082 lb/MMBtu and 1.7 lbs/hr, based on a 3 - hour average through the use of good combustion and low NOx burners.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for CO for Dew Point Heater (EU-4).

The CO emissions from the Dew Point Heater (EU-4) operation shall not exceed 0.082 lb/MMBtu and 1.7 lbs/hr, based on a 3 - hour average through the use of good combustion and low NOx burners.

Volatile Organic Compounds (VOCs) BACT - Dew Point Heater EU-4

Step 1: Identify Potential Control Technologies

Emissions of Volatile Organic Compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer

(c) Catalytic oxidation;

(d) Good Combustion Controls; and

(e) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling VOCs emissions. Upon passing through the flame, the waste gas containing VOCs is heated. The mixture continues to react as it flows through the combustion chamber. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

The required level of VOCs destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is a technically feasible option for the Dew Point Heater at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1,200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Dew Point Heater at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOCs emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Dew Point Heater at this source.

Flare
Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for VOCs from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Dew Point Heater at this source

Good Combustion Controls
Good combustion controls is a continued operation of the Boilers at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation. Because VOC is

essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of VOC emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the Dew Point Heater at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - (75% destruction efficiency); and

(2) Combustion Control via good combustion design and low NOx burners

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOCs BACT determination along with the existing VOCs BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Dew Point Heater (EU-4)**	**20.8 MMBtu/hr**	**VOCs: 0.0053 lb/MMBtu and 0.42 lb/hr, based on 3-hr average**	**Good Combustion Design and low NOx Burners**
LA-0237	International Matex Tank Terminal	05/20/2010	Heaters (6)	37.80 MMBtu/hr, each	0.0055 lb/mmbtu	None
OK-0134	Pryor Plant Chemical Company	02/23/2009	Nitric Acid Preheaters No. 1	20 MMBtu/hr	0.11 lb/hr and 0.0050 lbs/MMBtu	None
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant	01/23/2009	Fuel Gas Heater	18.8 MMBtu/hr	0.1 lb/hr ad 0.0053 lbs/MMBtu	None

As shown in the above table, a limit of 0.0053 lb/MMBtu which is the most stringent is consistent with the other limits contained in the RBLC.

The cost of add-on control technology to control VOC emissions is not cost effective due to the low concentration of VOC in the exhaust stream. The U.S. EPA’s Air Pollution Control Technology Fact Sheet for Regenerative Incinerators (EPA-452/F-03-021) provides annualized costs ranging from $8 to $33/cfm for regenerative thermal oxidizers and $11 to $41/cfm for catalytic oxidizers. The dew point heater has a design exhaust flow rate of approximately 6,400 cfm, and a low maximum potential VOC emission rate (0.48 tpy based on 8,760 hours per year at full load). Using a conservative cost of $8/cfm, the cost effectiveness of installing add-on controls would be at least $593,750 per ton of VOC removed.

The following has been proposed as BACT for VOC emissions from the proposed Dew Point Heater (EU-4):

The VOC emissions from the Dew Point Heater, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.11 lbs/hr, based on a 3-hr average period through the use of good combustion and low NOx burners.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for VOC for the Dew Point Heater (EU-4).

The VOC emissions from the Dew Point Heater, identified as EU-3 shall not exceed 0.0053 lb/MMBtu and 0.11 lbs/hr, based on a 3-hr average period through the use of good combustion and low NOx burners.

Nitrogen Oxide (NOx) BACT - Dew Point Heater EU-4

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR)

(b) Selective Non-Catalytic Reduction (SNCR)

(c) SCONOx Catalytic Absorption System

(d) Ultra-Low NOx Burners (LNB)

Step 2: Eliminate Technically Infeasible Options

Add-on Control Technology:
NO_x add-on controls including SCR and SNCR are not considered to be technically feasible for small natural gas fired heaters such as the dew point heater. These technologies would not be cost effective for small natural gas-fired heaters. Due to their small size and limited use, the emissions would not be significant and would result in excessive cost per ton removed of emissions. No such technology has ever been installed or demonstrated in practice for a small natural gas fired heater. Further, these technologies would unnecessarily increase emissions of NH_3, a precursor to the atmospheric formation of the non-attainment pollutant $PM_{2.5}$. This adverse environmental impact would render the use of SNCR or SCR as the BACT for the $PM_{2.5}$ precursor NOx counterproductive to the goal of decreasing ambient levels of $PM_{2.5}$.

Flue Gas Recirculation
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NO_x production. The flue gas recirculation (FGR) can be highly effective technique for lowering NO_x emissions from burners and it's relatively inexpensive to apply. Most of the early FGR work was done on boilers, and investigators found that recirculating up to 25% of the flue gases through the burner could lower NO_x emissions to as little as 25% of their normal levels. FGR can lower NO_x emissions in two ways: the cooled, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and

lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NO_x-forming reaction for one of the ingredients they need.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of flue gas recirculation is a technically feasible option for the Dew Point Heater at this source.

Low NOx Burner (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and fuel, as well as other methods that effectively lower the flame temperature. In the drive to reduce NOx emissions, NOx reduction techniques were implemented to lower peak flame temperature.

The ULNBs are specially designed pieces of combustion equipment that reduce NOx formation through careful control of the fuel-air mixture during combustion. In a staged air combustion LNB, either air or fuel is added downstream of the primary combustion zone. Depending on which of these NOx reduction techniques is used, LNBs with staged combustion are subdivided into staged air burners and staged fuel burners.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one burner installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible especially when another NOx reduction technique is used in conjunction with LNBs.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of low NOx burners is a technically feasible option for the Dew Point Heater at this source.

SCONOx Catalytic Absorption System
SCONOx Catalytic Absorption System utilizes a single catalyst to remove NO_X, CO, and VOC through oxidation. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. The Operating Temperature ranges from 300 - 700 °F. The $SCONO_X$ Catalyst is sensitive to contamination by sulfur, so it must be used in conjunction with the $SCOSO_X$ catalyst, which favors sulfur compound absorption. This technology has only been demonstrated on units ranging from 5 to 45 MW.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective SCONOx Catalytic Absorption System is not a technically feasible option for the Dew Point Heater at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Natural gas firing with low NO_x Burner with Flue Gas Recirculation (LNB/FGR)

(2) Natural gas firing with low NO_x Burner (LNB)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Dew Point Heater (EU-4)**	**20.8 MMBtu/hr**	**NOx: 0.032 lb/MMBtu and 0.67 pounds per hour, based on 3-hr average**	**Low NOx Burner with Flue Gas Recirculation**
LA-0262	Cornerstone Chemical Company	05/03/2012	Acid Plant Air Preheater	86 MMBtu/hr	2.96 lb/hr max, 0.034 lb/MMBtu and 11.79 tpy	External FGR and low NO_x burners
AK-0071	Chugach Electric Association, Inc., International Station Power Plant	12/20/2010	Sigma Thermal Auxiliary Heater	12.5 MMBtu/hr	32.0 lb/MMscf, 3-hr avg	Low NO_x burners and FGR
LA-0237	International Matex Tank Terminal	05/20/2010	Heaters (6)	37.80 MMBtu/hr, each	0.036 lb/hr	Low NO_x burners
WY-0066	Medicine Bow Fuel & Power	03/04/2009	Gasification Preheaters (5)	21 MMBtu/hr (each)	0.05 lb/MMBtu	Low NO_x burners
OK-0134	Pryor Plant Chemical Company	02/23/2009	Nitric Acid Preheaters No. 1	20 MMBtu/hr	0.98 lb/hr, 168-hr rolling average	Low NO_x burners
OK-0129	Associated Electric Cooperative, Inc. Chouteau Power Plant	01/23/2009	Fuel Gas Heater	18.8 MMBtu/hr	2.7 lb/hr	None
IA-0064	Roquette America	01/31/2003	Dew Point Heater	1.6 MMBtu/hr	0.15 lb/MMBtu; 0.24 lb/hr	None
IA-0058	Midamerican Energy, Greater Des Moines Energy Center	04/10/2002	Dew Point Heater	NA	0.036 lb/MMBtu; 1.47 tpy	None

As shown in the above table, a limit of 0.032 lb/MMBtu which is the most stringent is consistent with the other limits contained in the RBLC.

The following has been proposed as BACT for NOx emissions from the proposed Dew Point Heater, identified as EU-4:

(1) The NOx emissions from the Dew Point Heater, identified as EU-4 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(2) The NOx emissions shall be limited to less than 0.032 lb/MMBtu and 0.67 pounds per hour, based on a 3-hr average period.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for NOx for the Dew Point Heater, identified as EU-4:

(1) The NOx emissions from the Dew Point Heater, identified as EU-4 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(2) The NOx emissions shall be limited to less than 0.032 lb/MMBtu and 0.67 pounds per hour, based on a 3-hr average period.

Particulate Matter (PM and PM_{10}) BACT –Emergency Generator (EU-5)

Step 1: Identify Potential Control Technologies

Emissions of PM and PM_{10} are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM and PM_{10} emissions are controlled through one of the following mechanisms:

(1) Catalyzed Diesel Particulate Filter (CDPF);

(2) Good Combustion Practices; and

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Catalyzed Diesel Particulate Filter (CDPF)
The particulate matter emissions in exhaust gas is trapped by a ceramic filter and oxidized using a metallic catalyst or a base. The operating temperature ranges between 480 - 570°F. The exhaust gas temperature must be high enough over an extended period of time to allow for filter regeneration. The type of control is not included in RBLC for the control of PM emissions from fire pump and emergency engines. EPA determined in the development of NSPS IIII that add-on controls are technically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Catalyzed Diesel Particulate Filter is not a technically feasible option for the Emergency Generator at this source.

Good Combustion Practices
The organic particulate matter emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form in the fuel injection plume that cause unburned fuel to pyrolize at the high engine temperature and form soot. Soot formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of emission control is included in RBLC for the control of particulate emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Emergency Generator at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the particulate emissions from the Emergency Generator at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM and PM_{10} BACT determination along with the existing PM and PM_{10} BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Emergency Generator EU-5**	**1,826 horsepower**	**PM and PM_{10}: 0.15 g/bhp-hr (0.2 g/kw-hr)**	**Combustion Design Controls**
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Emergency Diesel Generators EG01 & EG02	1,006 horsepower, each	PM, PM_{10} and $PM_{2.5}$: 0.15 g/bhp-hr	Combustion Design Controls and Usage Limits
			Emergency Generator EG03	2,012 horsepower		
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Generator, fuel oil-fired	564 kw	0.2000 g/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Generators, fuel oil-fired	2,682 HP each	0.2000 g/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative, Deer Creek Station	06/29/2010	Emergency Generator	2,000 KW	Requirements of NSPS, Subpart IIII	None
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Emergency Generator Engine	750 KW	0.200 g/kw-hr, Tier 2 engine-based	None

The proposed diesel-fired emergency generators will be subject to the NESHAP found at 40 CFR 63 Subpart ZZZZ and the NSPS found at 40 CFR 60 Subpart IIII, which apply to stationary compression ignition reciprocating engines. The standards establish particulate limits and compliance with the limits is demonstrated by purchasing certified engines.

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Emergency Generator:

The PM and PM_{10} emissions from the Emergency Generator, Identified as EU-5, shall not exceed 0.15 g/hp-hr, through the use of combustion design control.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for PM and PM_{10} for the Emergency Generator (EU-5).

The PM and PM_{10} emissions from the Emergency Generator, Identified as EU-5, shall not exceed 0.15 g/hp-hr, through the use of combustion design control.

Particulate Matter ($PM_{2.5}$) BACT–Emergency Generator (EU-5)

Step 1: Identify Potential Control Technologies

Emissions of $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Catalyzed Diesel Particulate Filter (CDPF);

(2) Good Combustion Practices; and

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Catalyzed Diesel Particulate Filter (CDPF)
The particulate matter emissions in exhaust gas is trapped by a ceramic filter and oxidized using a metallic catalyst or a base. The operating temperature ranges between 480 - 570°F. The exhaust gas temperature must be high enough over an extended period of time to allow for filter regeneration. The type of control is not included in RBLC for the control of PM emissions from fire pump and emergency engines. EPA determined in the development of NSPS IIII that add-on controls are technically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Catalyzed Diesel Particulate Filter is not a technically feasible option for the Emergency Generator at this source.

Good Combustion Practices
The organic particulate matter emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form in the fuel injection plume that cause unburned fuel to pyrolize at the high engine temperature and form soot. Soot

formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of emission control is included in RBLC for the control of particulate emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Emergency Generator at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the particulate emissions from the Emergency Generator at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM_{2.5}$ BACT determination along with the existing $PM_{2.5}$ BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Emergency Generator EU-5**	**1,826 horsepower**	**$PM_{2.5}$: 0.15 g/bhp-hr (0.2 g/kw-hr)**	**Combustion Design Controls**
Draft Permit No. 141-31003-00579 Proposed Limit	St. Joseph Energy Center - *proposed*	12/03/2012	Emergency Diesel Generators EG01 & EG02	1,006 horsepower, each	PM, PM_{10} and $PM_{2.5}$: 0.15 g/bhp-hr	Combustion Design Controls and Usage Limits
			Emergency Generator EG03	2,012 horsepower		
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Generator, fuel oil-fired	564 kw	0.2000 g/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Generators, fuel oil-fired	2,682 HP each	0.2000 g/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative, Deer Creek Station	06/29/2010	Emergency Generator	2,000 KW	Requirements of NSPS, Subpart IIII	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Emergency Generator Engine	750 KW	0.200 g/kw-hr, Tier 2 engine-based	None

The proposed diesel-fired emergency generators will be subject to the NESHAP found at 40 CFR 63 Subpart ZZZZ and the NSPS found at 40 CFR 60 Subpart IIII, which apply to stationary compression ignition reciprocating engines. The standards establish particulate limits and compliance with the limits is demonstrated by purchasing certified engines.

The following has been proposed as BACT for $PM_{2.5}$ from the proposed Emergency Generator:

The $PM_{2.5}$ emissions from the Emergency Generator, Identified as EU-5, shall not exceed 0.15 g/hp-hr, through the use of combustion design control.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for $PM_{2.5}$ for the Emergency Generator (EU-5).

The $PM_{2.5}$ emissions from the Emergency Generator, Identified as EU-5, shall not exceed 0.15 g/hp-hr, through the use of combustion design control.

Sulfuric Acid (H_2SO_4) BACT – Emergency Generator (EU-5)

Step 1: Identify Potential Control Technologies

Emissions of Sulfuric Acid (H_2SO_4) emissions depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. Sulfuric Acid (H_2SO_4) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Flue Gas Desulfurization (FGD) System);

(2) Dry Sorbent Injection; and

(3) Fuel Specification.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. H_2SO_4 emissions are not dependent upon combustion turbine properties such as size or burner design.

Step 2: Eliminate Technically Infeasible Options

<u>Add-on Control Technology:</u>
Add-on particulate control devices such as Flue Gas Desulfurization (FGD) System, Dry Sorbent Injection are not possible alternatives because the potential H_2SO_4 emissions from emergency engines are very minor, given their limited hours of operation. With such insignificant emissions, it would not be considered feasible to employ add-on control technologies to reduce H_2SO_4emissions from emergency engines. Additionally, since control technologies have not

been implemented in practice to control emissions from emergency engines, there is no evidence that such measures would be technically feasible.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating H_2SO_4 emissions. Fuel Specifications is included in RBLC for the control of H_2SO_4 from combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the emergency generator (EU-5) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of H_2SO_4 resulting from the operation of the emergency generator (EU-5).

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed H_2SO_4 BACT determination along with the existing H_2SO_4 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Generator EU-5**	**1,826 horsepower**	**H_2SO_4: sulfur content of 15ppm**	**Ultra-low sulfur diesel fuel**
MD-0040	Competitive Power Ventures, Inc., CPV St. Charles	11/12/2008	Diesel-fired Emergency Generator	1,500 KW	Exclusive use of ultra-low sulfur diesel with sulfur content not to exceed 15 ppm	None
WI-0228	Wisconsin Public Service, Weston Plant		Diesel-fired Booster Pump	265 HP	0.0832 lb/hr, 200 hr/12 month rolling limit; 0.003 wt% sulfur in diesel fuel	None
			Main Fire Pump	460 HP	0.014 lb/hr, 200 hr/12 month rolling limit; 0.003 wt% sulfur in diesel fuel	None

IDEM is proposing a weight percent (wt %) of sulfur in the diesel fuel of 0.75 gr S/100 scf which is the most stringent limit for H_2SO_4 emissions. Note that H_2SO_4 emissions depend on the sulfur content of the natural gas available to the facility. The proposed facility will have access to natural gas from a single supplier for the region, and will not have the option to receive natural gas from any other source or require the supplier to provide lower sulfur content fuel.

The following has been proposed as BACT for H_2SO_4 emissions from the proposed emergency generator, identified as EU-5:

The H_2SO_4 emissions from the emergency generator, identified as EU-5 is proposed to be the use of ultra low S diesel fuel.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for H_2SO_4 for the emergency generator (EU-5).

(1) The sulfur content of the fuel oil shall not exceed 15ppm.

Carbon Monoxide (CO) BACT – Emergency Generator (EU-5)

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer;

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the waste gas containing CO is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of CO destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the Emergency Generator at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Emergency Generator at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Emergency Generator at this source.

Flare
Although the CO concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Emergency Generator at this source.

Combustion Design Controls
CO emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in CO and unburned hydrocarbons that exit with the exhaust. CO formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of control is included in RBLC for the control of CO emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Generator at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the CO emissions from the Emergency Generator at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Generator EU-5**	**1,826 horsepower**	**CO: 2.6 g/bhp-hr (3.5 g/kw-hr)**	**Combustion Design Controls**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Emergency Diesel Generators EG01 & EG02	1,006 horsepower, each	CO: 2.6 g/bhp-hr	Combustion Design Controls and Usage Limits
			Emergency Generator EG03	2,012 horsepower		
SC-0113	Pyramax Ceramics, LLC	02/08/2012	Emergency Engines, diesel-fired	29 HP each	5.500 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
			Emergency Generators, diesel-fired	757 HP each	3.500 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Generator, fuel oil-fired	564 kw	3.500 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Generators, fuel oil-fired	2,682 HP each	3.500 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative, Deer Creek Station	06/29/2010	Emergency Generator	2,000 KW	Requirements of NSPS, Subpart IIII	None
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Emergency Generator Engine	750 KW	3.5 g/kw-hr, Tier 2 engine-based	None

The proposed diesel-fired emergency generators will be subject to the NESHAP found at 40 CFR 63 Subpart ZZZZ and the NSPS found at 40 CFR 60 Subpart IIII, which apply to stationary compression ignition reciprocating engines. The standards establish CO limits and compliance with the limits is demonstrated by purchasing certified engines.

The following has been proposed as BACT for CO emissions from the proposed Emergency Diesel Generators, Identified as EU-5:

The CO emissions from the Emergency Generators, Identified as EU-5 shall not exceed 2.6 g/hp-hr through the use of combustion design controls.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for CO emissions for the Emergency Generator (EU-5).

The CO emissions from the Emergency Generators, Identified as EU-5 shall not exceed 2.6 g/hp-hr through the use of combustion design controls.

Volatile Organic Compounds (VOCs) BACT - Emergency Generator (EU-5)

Step 1: Identify Potential Control Technologies

Emissions of volatile organic compounds (VOC) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidation;

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling VOC emissions. Upon passing through the flame, the waste gas containing VOC is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of VOC destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the Emergency Diesel Generators at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Emergency Diesel Generators at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Emergency Diesel Generators at this source.

Flare
Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel.

Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for VOC from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Emergency Diesel Generators at this source.

Combustion Design Controls
VOC emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in VOC and unburned hydrocarbons that exit with the exhaust. VOC formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of control is included in RBLC for the control of VOC emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Diesel Generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the VOC emissions from the Emergency Generators at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Generator EU-5**	**1,826 horsepower**	**4.8 g/bhp-hr**	**Combustion Design Controls**
Permit No. 141-31003-00579	St. Joseph Energy Center	Proposed	Emergency Diesel Generators EG01 & EG02	1,006 horsepower, each	VOC: 1.04 lbs/hr, each	Combustion Design Controls and Usage Limits
			Emergency Generator EG03	2,012 horsepower	VOC: 1.04 lbs/hr	
SC-0113	Pyramax Ceramics, LLC	02/08/2012	Emergency Engines, diesel-fired	29 HP each	7.500 g/kw-H (purchase of NSPS, Subpart IIII certified engine)	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
			Emergency Generators, diesel-fired	757 HP each	4.000 g/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
IA-0102	Alcoa, Inc. Davenport Works	02/01/2012	Emergency Generator	2115 cf/hr (225 kw)	0.66 lb/hr	None
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Emergency Generator Engine	750 KW	6.4 g/kw-hr (NO_x + NMHC), Tier 2 engine-based	None

As shown in the above table, the source has proposed a limit of 4.8 g/bhp-hr NOx + NMHC, which is equivalent to 0.011 lb/bhp-hr, which is consistent with the most stringent limits contained in the RBLC.

The following has been proposed as BACT for VOC emissions from the proposed Emergency Generator, Identified as EU-5:

The VOC emissions from the Emergency Generator shall be limited to less than 4.8 g/bhp-hr through the use of Combustion Design Controls.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for VOC emissions for the Emergency Diesel Generator (EU-5).

The VOC emissions from the Emergency Generator shall be limited to less than 4.8 g/bhp-hr through the use of Combustion Design Controls.

Nitrogen Oxide (NOx) BACT - Emergency Generator (EU-5)

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR)

(b) Selective Non-Catalytic Reduction (SNCR); and

(c) Combustion Design Controls.

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750 F. Temperature below the optimum, decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a sootblower.

This control is not included in RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is not a technically feasible option for the Emergency Diesel Generators at this source.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2100°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water.
This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction. At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of a competing reaction for the direct oxidation of ammonia that actually forms NO_x becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the source exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range.

This control is not included in the RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is not a technically feasible option for the Emergency Diesel Generators at this source.

Combustion Design Controls
NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and exhaust gas recirculation. This type of control is included in RBLC for the control of NO_X emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Diesel Generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the NOx emissions from the Emergency Generators at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for emergency pumps. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Generator EU-5**	**1,826 horsepower**	**NMNC + NOx: 4.8 g/bhp-hr**	**Combustion Design Controls**
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Emergency Diesel Generators EG01 & EG02	1,006 horsepower, each	NOx + NMNC: 4.8 g/bhp-hr	Combustion Design Controls and Usage Limits
			Emergency Generator EG03	2,012 horsepower		
SC-0113	Pyramax Ceramics, LLC	02/08/2012	Emergency Engines, diesel-fired	29 HP each	7.500 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
			Emergency Generators, diesel-fired	757 HP each	4.000 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
LA-0251	Flopam, Inc.	04/26/2011	Large Diesel-fired Engines	591 – 1,175 hp	6.4000 g/kw-hr (NO_x + NMHC); 6.3200 lb/hr (591 HP units); 10.3600 lb/hr (1175 HP units) (LAER)	None
FL-0329	Shell Offshore, Inc.	11/28/2011	Standby Generator – Deepwater Nautilus, diesel-fired	NA	0.15 tpy	Use of turbo charger after cooler, intake air cooling

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
			Emergency Generator – Bully	NA	0.15 tpy	Use of EPA Tier 2 engines with low NO_x engine design
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Generator, fuel oil-fired	564 kw	6.4000 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Generators, fuel oil-fired	2,682 HP each	6.4000 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative, Deer Creek Station	06/29/2010	Emergency Generator	2,000 KW	Requirements of NSPS, Subpart IIII	None
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Emergency Generator Engine	750 KW	6.4 g/kw-hr (NO_x + NMHC), Tier 2 engine-based	None
CA-0988	Pacific Bell	02/01/2003	Emergency Generator	2,935 HP	6.9000 g/bhp-hr (LAER)	None
CA-0998	Western Devcon	01/07/2003	Emergency Generator	415 HP	6.9000 g/bhp-hr (LAER)	None
CA-0991	Cenic DBA UC Davis Communications Resources	08/09/2002	Emergency Generator	277 HP	6.9000 g/bhp-hr (LAER)	None
CA-0989	Folsom Surgical Center	05/01/2002	Emergency Generator	68 HP	6.9000 g/bhp-hr (LAER)	None

As shown in the above table, a proposed limit of 4.8 g/bhp-hr NOx + NMHC, which is equivalent to 0.011 lb/bhp-hr, which is consistent with the most stringent limits contained in the RBLC.

The following has been proposed as BACT for NOx emissions from the proposed Emergency Generators, Identified as EU-5:

The NOx emissions from the Emergency Generator shall be limited to less than 4.8 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for NOx emissions for the Emergency Generator (EU-5).

The NOx emissions from the Emergency Generator shall be limited to less than 4.8 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

Particulate Matter (PM and PM_{10}) BACT – Emergency Fire Pump (EU-6)

Step 1: Identify Potential Control Technologies

Emissions of PM and PM_{10} are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM and PM_{10} emissions are controlled through one of the following mechanisms:

(1) Catalyzed Diesel Particulate Filter (CDPF); and

(2) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Catalyzed Diesel Particulate Filter (CDPF)
The particulate matter emissions in exhaust gas is trapped by a ceramic filter and oxidized using a metallic catalyst or a base. The operating temperature ranges between 480 - 570°F. The exhaust gas temperature must be high enough over an extended period of time to allow for filter regeneration. The type of control is not included in RBLC for the control of PM emissions from fire pump and emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Catalyzed Diesel Particulate Filter is not a technically feasible option for the Firewater Pump Engine at this source.

Good Combustion Practices
The organic particulate matter emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form in the fuel injection plume that cause unburned fuel to pyrolize at the high engine temperature and form soot. Soot formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of emission control is included in RBLC for the control of particulate emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Firewater Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

1. Good Combustion Practices.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the particulate emissions from the fire pump engines at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM and PM_{10} BACT determination along with the existing PM and PM_{10} BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Fire Pump**	**500 horsepower**	**PM and PM_{10}: 0.15 g/bhp-hr**	**Combustion Design Controls**
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Firewater Pump Engines	371 brake horsepower	PM, PM_{10} and $PM_{2.5}$: 0.15 g/bhp-hr	Combustion Design Controls and Usage Limits
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Diesel Fire Pump	275 hp	0.1500 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Diesel Fire Pump	NA	0.1500 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
FL-0324	Solid Waste Authority of Palm Beach County, Palm Beach Renewable Energy Park	12/23/2010	Emergency Diesel Fire Pump	250 HP	0.1500 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative, Deer Creek Station	06/29/2010	Diesel Fire Water Pump	577 HP	Requirements of NSPS, Subpart IIII	None
ID-0018	Idaho Power Co., Langley Gulch Power Plant	06/25/2010	Diesel Fire Pump Engine	235 KW	0.2000 g/kw-hr (Tier 3 engine-based) [converts to 0.15 g/hp-hr]	None

As shown in the above table, a proposed limit of 0.15 g/bhp-hr, which is equivalent to 0.20 g/kW-hr, is consistent with the most stringent limits contained in the RBLC.

The following has been proposed as BACT for PM and PM_{10} from the proposed Emergency Fire Pump Engines:

(1) The PM and PM_{10} emissions from the Emergency Fire Pump Engine shall not exceed 0.15 g/hp-hr through the use of combustion design control.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for PM and PM_{10} for the Fire Pump Engine (EU-6).

(1) The PM and PM_{10} emissions from the Emergency Fire Pump Engine shall not exceed 0.15 g/hp-hr through the use of combustion design control.

Particulate Matter ($PM_{2.5}$) BACT – Emergency Fire Pump (EU-6)

Step 1: Identify Potential Control Technologies

Emissions of $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Catalyzed Diesel Particulate Filter (CDPF); and

(2) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Catalyzed Diesel Particulate Filter (CDPF)
The particulate matter emissions in exhaust gas is trapped by a ceramic filter and oxidized using a metallic catalyst or a base. The operating temperature ranges between 480 - 570°F. The exhaust gas temperature must be high enough over an extended period of time to allow for filter regeneration. The type of control is not included in RBLC for the control of PM emissions from fire pump and emergency engines. EPA determined in the development of NSPS IIII that add-on controls are technically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Catalyzed Diesel Particulate Filter is not a technically feasible option for the Firewater Pump Engine at this source.

Good Combustion Practices
The organic particulate matter emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form in the fuel injection plume that cause unburned fuel to pyrolize at the high engine temperature and form soot. Soot formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of emission control is included in RBLC for the control of particulate emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Practices is a technically feasible option for the Firewater Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

1. Good Combustion Practices.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the particulate emissions from the fire pump engines at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM_{2.5}$ BACT determination along with the existing $PM_{2.5}$ BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Fire Pump**	**500 horsepower**	**$PM_{2.5}$: 0.15 g/bhp-hr**	**Combustion Design Controls**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Firewater Pump Engines	371 brake horsepower	PM, PM_{10} and $PM_{2.5}$: 0.15 g/bhp-hr	Combustion Design Controls and Usage Limits
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Diesel Fire Pump	275 hp	0.1500 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Diesel Fire Pump	NA	0.1500 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
FL-0324	Solid Waste Authority of Palm Beach County, Palm Beach Renewable Energy Park	12/23/2010	Emergency Diesel Fire Pump	250 HP	0.1500 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative,	06/29/2010	Diesel Fire Water Pump	577 HP	Requirements of NSPS, Subpart IIII	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
	Deer Creek Station					
ID-0018	Idaho Power Co., Langley Gulch Power Plant	06/25/2010	Diesel Fire Pump Engine	235 KW	0.2000 g/kw-hr (Tier 3 engine-based) [converts to 0.15 g/hp-hr]	None

As shown in the above table, a proposed limit of 0.15 g/bhp-hr, which is equivalent to 0.20 g/kW-hr, is consistent with the most stringent limits contained in the RBLC.

The following has been proposed as BACT for $PM_{2.5}$ from the proposed Emergency Fire Pump Engine:

The $PM_{2.5}$ emissions from the Emergency Fire Pump Engine shall not exceed 0.15 g/hp-hr through the use of combustion design control.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for $PM_{2.5}$ for the Fire Pump Engine (EU-6).

The $PM_{2.5}$ emissions from the Emergency Fire Pump Engine shall not exceed 0.15 g/hp-hr through the use of combustion design control.

Sulfuric Acid (H_2SO_4) BACT – Emergency Fire Pump (EU-6)

Step 1: Identify Potential Control Technologies

Emissions of Sulfuric Acid (H_2SO_4) emissions depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. Sulfuric Acid (H_2SO_4) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Flue Gas Desulfurization (FGD) System;

(2) Dry Sorbent Injection; and

(3) Fuel Specification.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. H_2SO_4 emissions are not dependent upon combustion turbine properties such as size or burner design.

Step 2: Eliminate Technically Infeasible Options

Add-on Control Technology:
Add-on particulate control devices such as Flue Gas Desulfurization (FGD) System, Dry Sorbent Injection are not possible alternatives because the potential H_2SO_4 emissions from emergency engines are very minor, given their limited hours of operation. With such insignificant emissions, it would not be considered feasible to employ add-on control technologies to reduce H_2SO_4emissions from emergency engines. Additionally, since control technologies have not

been implemented in practice to control emissions from emergency engines, there is no evidence that such measures would be technically feasible.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating H_2SO_4 emissions. Fuel Specifications is included in RBLC for the control of H_2SO_4 from Emergency Fire pump.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Emergency Fire pump (EU-6) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of H_2SO_4 resulting from the operation of the combined cycle combustion turbines (EU-6).

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed H_2SO_4 BACT determination along with the existing H_2SO_4 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Fire Pump**	**500 horsepower**	**H_2SO_4: sulfur content of 15 ppm**	**Ultra-low sulfur diesel fuel**
MD-0040	Competitive Power Ventures, Inc., CPV St. Charles	11/12/2008	Diesel-fired Emergency Generator	1,500 KW	Exclusive use of ultra-low sulfur diesel with sulfur content not to exceed 15 ppm	None
WI-0228	Wisconsin Public Service, Weston Plant	10/19/2004	Diesel-fired Booster Pump	265 HP	0.0832 lb/hr, 200 hr/12 month rolling limit; 0.003 wt% sulfur in diesel fuel	None
			Main Fire Pump	460 HP	0.014 lb/hr, 200 hr/12 month rolling limit; 0.003 wt% sulfur in	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
					diesel fuel	

IDEM is proposing a Ultra-low sulfur diesel fuel of 0.75 gr S/100 scf which is the most stringent limit for H_2SO_4 emissions. Note that H_2SO_4 emissions depend on the sulfur content of the fuel available to the facility. The proposed facility will have access to fuel from a single supplier for the region, and will not have the option to receive fuel from any other source or require the supplier to provide lower sulfur content fuel.

The following has been proposed as BACT for H_2SO_4 emissions from the proposed Emergency Fire pump, identified as EU-6:

(a) The sulfur content for the fuel oil shall not exceed 15ppm.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for H_2SO_4 for the Emergency Fire Pump Engine (EU-6).

(a) The sulfur content for the fuel oil shall not exceed 15ppm.

Carbon Monoxide (CO) BACT – Emergency Fire Pump (EU-6)

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidation;

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the waste gas containing CO is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of CO destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the Emergency Fire pump Engine at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Emergency Fire pump Engine at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Emergency Fire pump Engine at this source.

Flare
Although the CO concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Emergency Fire pump Engine at this source.

Combustion Design Controls
CO emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in CO and unburned hydrocarbons that exit with the exhaust. CO formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of control is included in RBLC for the control of CO emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Fire pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control shall be used to reduce the CO emissions from the Emergency Fire pump Engine at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-	**IPL Eagle Valley Generating**	**Proposed**	**Emergency Fire Pump**	**500 horsepower**	**CO: 2.6 g/bhp-hr (3.5 g/kw-hr)**	**Combustion Design Controls**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
00004 Proposed Limit	**Station**					
Permit No. 141-31003-00579	St. Joseph Energy Center	12/03/2012	Firewater Pump Engines	371 brake horsepower	CO: 2.6 g/bhp-hr	Combustion Design Controls and Usage Limits
SC-0113	Pyramax Ceramics, LLC	02/08/2012	Fire Pump, diesel-fired	500 hp	3.500 gr/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Diesel Fire Pump	275 hp	2.6 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Diesel Fire Pump	NA	2.6 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
FL-0324	Solid Waste Authority of Palm Beach County, Palm Beach Renewable Energy Park	12/23/2010	Emergency Diesel Fire Pump	250 HP	2.6 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative, Deer Creek Station	06/29/2010	Diesel Fire Water Pump	577 HP	Requirements of NSPS, Subpart IIII	None
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Diesel Fire Pump Engine	235 KW	No emission limits are available; Tier 3 engine-based	None

As shown in the above table, a proposed limit of 2.6 g/bhp-hr, which is equivalent to 3.5 g/kW-hr and 0.006 lb/bhp-hr, is consistent with the most stringent limits contained in the RBLC.

The following has been proposed as BACT for CO emissions from the proposed Emergency Fire pump Engine:

(1) The CO emissions from the Emergency Fire Pump Engine shall not exceed 2.6 g/hp-hr through the use of combustion design controls.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for CO emissions for the Fire Pump Engine (EU-6).

(1) The CO emissions from the Emergency Fire pump Engine shall not exceed 2.6 g/hp-hr through the use of combustion design controls.

Volatile Organic Compounds (VOCs) BACT - Emergency Fire Pump (EU-6)

Step 1: Identify Potential Control Technologies

Emissions of volatile organic compounds (VOC) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidation;

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling VOC emissions. Upon passing through the flame, the waste gas containing VOC is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of VOC destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.
The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the Emergency Fire pump Engine at this source.

Recuperative Thermal Oxidizers

This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{o}F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Emergency Fire pump Engine at this source.

Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency. This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Emergency Fire pump Engine at this source.

Flare

Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for VOC from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Emergency Fire pump Engine at this source.

Combustion Design Controls
VOC emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in VOC and unburned hydrocarbons that exit with the exhaust. VOC formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion. This type of control is included in RBLC for the control of VOC emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Fire Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control shall be used to reduce the VOC emissions from the Emergency Fire Pump Engine at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Fire Pump**	**500 horsepower**	**VOC: 3.0 g/bhp-hr**	**Combustion Design Controls and Usage Limits**
Permit No. 141-31003-00579	St. Joseph Energy Center *- proposed*	12/03/2012	Firewater Pump Engines	371 brake horsepower	VOC: 0.16 lbs/hr	Combustion Design Controls and Usage Limits
SC-0113	Pyramax Ceramics, LLC	02/08/2012	Fire Pump, diesel-fired	500 hp	4.000 g/kw-H (purchase of NSPS certified engine)	None
ID-0018	Idaho Power Co., Langley Gulch Power	06/25/2010	Diesel Fire Pump Engine	235 KW	4.000 g/kw-hr (NO_x + NMHC), Tier 3	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
	Plant				engine-based	

As shown in the above table, a limit of 3.0 g/bhp-hr which is the most stringent is consistent with the other limits contained in the RBLC.

The following has been proposed as BACT for VOC emissions from the proposed Emergency Fire pump Engine:

The VOC emissions from the Emergency Fire Pump Engine shall not exceed 3.0 g/bhp-hr through the use of Combustion Design Control.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC emissions for the Fire Pump Engine (EU-6).

The VOC emissions from the Emergency Fire pump Engine shall not exceed 3.0 g/bhp-hr through the use of Combustion Design Control.

Nitrogen Oxide (NOx) BACT - Emergency Fire Pump (EU-6)

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR)

(b) Selective Non-Catalytic Reduction (SNCR); and

(c) Combustion Design Controls.

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750 F. Temperature below the optimum, decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a sootblower.

This control is not included in RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is not a technically feasible option for the Emergency Fire Pump Engine at this source.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2100°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.
At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of a competing reaction for the direct oxidation of ammonia that actually forms NO_x becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NOx control performance therefore requires that the source exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range.

This control is not included in RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is not a technically feasible option for the Emergency Fire Pump Engine at this source.

Combustion Design Controls
NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and exhaust gas recirculation. This type of control is included in RBLC for the control of NO_X emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Fire Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

1. Good Combustion Controls.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control shall be used to reduce the NOx emissions from the Emergency Fire Pump Engine at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for emergency pumps. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (HP or KW)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Emergency Fire Pump**	**500 horsepower**	**NMNC + : NOx 3.0 g/bhp-hr**	**Combustion Design Controls**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Firewater Pump Engines	371 brake horsepower	NOx + NMNC: 3.0 g/bhp-hr	Combustion Design Controls and Usage Limits
SC-0113	Pyramax Ceramics, LLC	02/08/2012	Fire Pump, diesel-fired	500 hp	4.0 g/kw-H (purchase of NSPS, Subpart IIII certified engine)	None
LA-0251	Flopam, Inc.	04/26/2011	Large Diesel-fired Engines	591 – 1,175 hp	6.4000 g/kw-hr (NO_x + NMHC); 6.3200 lb/hr (591 HP units); 10.3600 lb/hr (1175 HP units) (LAER)	None
FL-0323	Gainesville Regional Utility Deerhaven, Renewable Energy Center	12/28/2010	Emergency Diesel Fire Pump	275 hp	3.000 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
FL-0322	Southeast Renewable Fuels, Sweet Sorghum-to-Ethanol Advanced Biorefinery	12/23/2010	Emergency Diesel Fire Pump	NA	3.000 g/hp-hr (purchase of NSPS, Subpart IIII certified engine)	None
SD-0005	Basin Electric Power Cooperative, Deer Creek Station	06/29/2010	Diesel Fire Water Pump	577 HP	Requirements of NSPS, Subpart IIII	None

As shown in the above table, a proposed limit of 3.0 g/bhp-hr, which is equivalent to 0.0066 lb/hp-hr, is consistent with the most stringent limits contained in the RBLC.

The following has been proposed as BACT for NOx emissions from the proposed Fire Pump Engines:

(1) The NOx emissions from the Emergency Fire Pump Engine shall not exceed 3.0 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for NOx emissions for the Fire Pump Engine (EU-6).

(1) The NOx emissions from the Emergency Fire Pump Engine shall not exceed 3.0 g/bhp-hr for NMHC + NOx through the use of Combustion Design Controls.

Particulate Matter (PM and PM_{10}) BACT – Cooling Tower EU-7

Step 1: Identify Potential Control Technologies

Emissions of Particulate Matter (PM and PM_{10}) from cooling towers are generally controlled by:

(1) Drift (Mist) eliminator system.

(2) Reducing TDS

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing the PM and PM_{10} emissions from the Cooling Towers.

Drift Eliminator System
Cooling towers are a source of particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions from the small amount of water mist that is entrained with the cooling air as “drift”. The cooling water contains small amounts of dissolved solids which become particulate ($PM/PM_{10}/PM_{2.5}$) emissions once the water mist evaporates. To reduce the drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

Particulate matter emissions occur from cooling towers when suspended solids contained in water used in the cooling tower becomes airborne as the water is circulated and cooled. Drift eliminators contain packing which is used to limit the amount of this particulate matter which becomes airborne during the cooling process. As mist passes through the packing, the particles in the air contact and adhere to the surface of the packing. As condensed water flows down this packing, these particles are removed.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a drift eliminator system is technically feasible option for the Cooling Tower at this source.

Reducing TDS
Particulate emissions are related to the level of Total Dissolved Solids (TDS) in the cooling water. The level of TDS is a function of the source water, and the recycle rate. The TDS level in the source water can be reduced by use of reverse osmosis. The amount of cooling water recycled is a function of the overall volume capacity of the water withdrawal system. Maximizing the recycling of the cooling water will also reduce the amount of water resources utilized and would also reduce the overall mass loading of the cooling water blow-down discharged to the river.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Reducing TDS is a technically feasible option for the Cooling Towers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Drift (Mist) eliminator system.

(2) Reducing TDS

The most effective method for control of particulate emissions resulting from operation of the cooling towers at this source is the use of high efficiency drift eliminators designed to 0.0005% maximum drift to maintain a drift loss as well as the maintenance of the equipment in good working order and operation per manufacturer's specifications. The source has chosen the drift eliminator to control particulate matter from their Cooling Towers.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM and PM_{10} BACT determination along with the existing PM and PM_{10} BACT determinations for cooling towers. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (gpm)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Cooling Tower (U-7)**	**192,000 gpm**	**0.0005% and TDS ≤ 5000mg/L**	**Drift Eliminator**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Cooling Towers (CT01 and CT02)	170,000 gpm	0.0005%	Drift Eliminator
LA-0254	Entergy Louisiana, LLC, Ninemile Point Electric Generating Plant	12/12/2011	Chiller Cooling Tower	12,000 gpm	$PM_{10}/PM_{2.5}$: 0.0010 % drift, annual average	High efficiency mist eliminator
			Unit 6 Cooling Tower	115,847 gpm	$PM_{10}/PM_{2.5}$: 0.0005% drift, annual average	High efficiency mist eliminator
WI-0252	Specialty Minerals, Inc. – Superior	07/22/2011	Cooling Towers P40, P50	700 gpm each	$PM_{10}/PM_{2.5}$: 0.0005% circulation drift	High efficiency drift / mist eliminator
			Cooling Tower P60	200 gpm	$PM_{10}/PM_{2.5}$: 0.0005% circulation drift; Dissolved Solids Limit of 1000 ppm; $PM_{2.5}$ is not more than 42% of total PM	High efficiency drift / mist eliminator
LA-0251	Flopam, Inc.	04/26/2011	Cooling Towers (10	3,640 gpm	PM_{10}: 0.01 lb/hr;	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (gpm)	Limitation	Control Method
	Facility		units)		0.01 tpy	
LA-0246	Valero Refining – New Orleans, LLC, St. Charles Refinery	12/31/2010	Cooling Towers	45,000 gpm - 61,250 gpm	PM_{10}: 0.08 - 1.2 lb/hr	Drift eliminators
LA-0248	Consolidated Environmental Management, Inc. Nucor / Direct Reduction Iron Plant	01/27/2011	DRI 113 & 213: Units #1 and 2 Process Water Cooling Tower	26,857 gpm	PM_{10}: TDS </= 1000 mg/L; Max drift of 0.0005%	Drift eliminators
			DRI 114 & 214: Unit #1 Clean Water Cooling Tower	17,611 gpm	PM_{10}: TDS </= 1000 mg/L; Max drift of 0.0005%	Drift eliminators
LA-0246	Valero Refining – New Orleans, LLC, St. Charles Refinery	12/31/2010	Cooling Towers	45,000 gpm - 61,250 gpm	PM_{10}: 0.08 - 1.2 lb/hr	Drift eliminators
GA-0142	Osceola Steel Co.	12/29/2010	Cooling Towers CT1, CT21, CT22, and CT23	NA	PM_{10}: 0.0005% mass flow rate; 1000 mg/L	Drift eliminators
FL-0323	Gainesville Regional Utility (GRU) Deerhaven	12/28/2010	Mechanical Draft Cooling Tower	78,000 gpm	PM_{10}: 0.0005% max drift	Drift eliminators
OH-0341	Nucor Steel Marion, Inc.	12/23/2010	Cooling Tower	NA	PM: 0.005% drift rate	Drift eliminators
NH-0018	Laidlaw Berlin Biopower, LLC	07/26/2010	Wet Cooling Tower	60,000 gpm	PM: 0.0005% drift rate	Drift eliminators
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Cooling Tower	63,200 gpm	NA	Drift eliminators
LA-0239	Consolidated Environmental Mgmt, Inc. Nucor Steel Louisiana	05/24/2010	Blast Furnace Cooling Tower, Iron Solidification Cooling Tower & Air Separation Plant Cooling Tower	NA	PM: TDS </= 1000 mg/L; Max drift of 0.0005%	Drift eliminators
TX-0552	Stark Power Generation II Holdings, LLC, Wolf Hollow Power Plant	03/03/2010	Cooling Tower	NA	PM: 0.0005% drift rate	Drift eliminators
TX-0551	Panda Sherman Power Station	02/03/2010	Cooling Tower	NA	PM: 0.0005% drift rate	Drift eliminators

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (gpm)	Limitation	Control Method
TX-0553	Lindale Renewable Energy, LLC	01/08/2010	Cooling Tower	NA	PM: 0.0005% drift rate	Drift eliminators
NV-0050	MGM Mirage	11/30/2009	Cooling Towers	10,890 gpm	PM_{10}: 0.001% drift rate and TSD concentration is limited to 3,600 ppm	Drift eliminators

The TDS requirements in cooling towers are very case specific due to available water supplies (quality and quantity), costs of equipment, size and use of cooling towers, site development limitations, and regulations governing water use. Te source is proposing to install cooling towers utilizing existing water wells to avoid impacts to the White River through installation of a new cooling water intake structure. By utilizing the well water, we start at higher values of TDS in the source water compared to the River. By relaxing the TDS limit in the air permit, this allows the source to use less water from the wells, and reduce impacts to the White River in the discharge. This occurs because less water is used and consequentially, there is less mass of dissolved material that subsequently requires discharge to the river.

Finally, managing TDS to lower levels than the proposed 5,000 mg/L would be extremely ineffective as a way to control particulate from the source. For example, PM2.5 from the cooling towers at 5000 mg/L assuming 8760 annual hours of operation yields 0.022 tpy while running at 1000 mg/L would yield 0.004 tpy, a difference of 0.018 tpy.

The following has been proposed as BACT for PM and PM_{10} emissions from the proposed Cooling Tower (U-7):

Therefore, a 0.0005% drift (mist) eliminator system is proposed as BACT for PM and PM_{10} emissions from the Cooling Towers, identified as U-7.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM, OAQ has approved the proposed PM and PM_{10} BACT for the Cooling Tower, identified as U-7.

(a) The PM and PM_{10} emissions from the Cooling Tower, identified as U-7 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and maximum total dissolved solids (TDS) shall be less than 5000 mg/L.

(b) The PM and PM_{10} emissions from the Cooling Tower shall be less than 2.4 and 1.5 pounds per hour, respectively.

Particulate Matter ($PM_{2.5}$) BACT – Cooling Tower U-7

Step 1: Identify Potential Control Technologies

Emissions of Particulate Matter ($PM_{2.5}$) from cooling towers are generally controlled by:

(1) Drift (Mist) eliminator system.

(2) Reducing TDS

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing the $PM_{2.5}$ emissions from the Cooling Towers.

Drift Eliminator System
Cooling towers are a source of particulate matter ($PM_{2.5}$) emissions from the small amount of water mist that is entrained with the cooling air as “drift”. The cooling water contains small amounts of dissolved solids which become particulate ($PM_{2.5}$) emissions once the water mist evaporates. To reduce the drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

Particulate matter emissions occur from cooling towers when suspended solids contained in water used in the cooling tower becomes airborne as the water is circulated and cooled. Drift eliminators contain packing which is used to limit the amount of this particulate matter which becomes airborne during the cooling process. As mist passes through the packing, the particles in the air contact and adhere to the surface of the packing. As condensed water flows down this packing, these particles are removed.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a drift eliminator system is technically feasible option for the Cooling Tower at this source.

Reducing TDS
Particulate emissions are related to the level of Total Dissolved Solids (TDS) in the cooling water. The level of TDS is a function of the source water, and the recycle rate. The TDS level in the source water can be reduced by use of reverse osmosis. The amount of cooling water recycled is a function of the overall volume capacity of the water withdrawal system. Maximizing the recycling of the cooling water will also reduce the amount of water resources utilized and would also reduce the overall mass loading of the cooling water blow-down discharged to the river.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Reducing dissolved solids is a technically feasible option for the Cooling Towers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Drift (Mist) eliminator system.

(2) Reducing TDS

The most effective method for control of particulate emissions resulting from operation of the cooling towers at this source is the use of high efficiency drift eliminators designed to 0.0005% maximum drift to maintain a drift loss as well as the maintenance of the equipment in good working order and operation per manufacturer’s specifications. The source has chosen the drift eliminator to control particulate matter from their Cooling Towers.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM_{2.5}$ BACT determination along with the existing $PM_{2.5}$ BACT determinations for cooling towers. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (gpm)	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Cooling Tower (U-7)**	**192,000 gpm**	**0.0005% and TDS ≤ 5000ppm**	**Drift Eliminator**
Permit No. 141-31003-00579	St. Joseph Energy Center - *proposed*	12/03/2012	Cooling Towers (CT01 and CT02)	170,000 gpm	0.0005%	Drift Eliminator
LA-0254	Entergy Louisiana, LLC, Ninemile Point Electric Generating Plant	12/12/2011	Chiller Cooling Tower	12,000 gpm	$PM_{10}/PM_{2.5}$: 0.0010 % drift, annual average	High efficiency mist eliminator
			Unit 6 Cooling Tower	115,847 gpm	$PM_{10}/PM_{2.5}$: 0.0005% drift, annual average	High efficiency mist eliminator
WI-0252	Specialty Minerals, Inc. – Superior	07/22/2011	Cooling Towers P40, P50	700 gpm each	$PM_{10}/PM_{2.5}$: 0.0005% circulation drift	High efficiency drift / mist eliminator
			Cooling Tower P60	200 gpm	$PM_{10}/PM_{2.5}$: 0.0005% circulation drift; Dissolved Solids Limit of 1000 ppm; $PM_{2.5}$ is not more than 42% of total PM	High efficiency drift / mist eliminator
LA-0251	Flopam, Inc. Facility	04/26/2011	Cooling Towers (10 units)	3,640 gpm	PM_{10}: 0.01 lb/hr; 0.01 tpy	None
LA-0246	Valero Refining – New Orleans, LLC, St. Charles Refinery	12/31/2010	Cooling Towers	45,000 gpm - 61,250 gpm	PM_{10}: 0.08 - 1.2 lb/hr	Drift eliminators
LA-0248	Consolidated Environmental Management, Inc. Nucor / Direct Reduction Iron Plant	01/27/2011	DRI 113 & 213: Units #1 and 2 Process Water Cooling Tower	26,857 gpm	PM_{10}: TDS </= 1000 mg/L; Max drift of 0.0005%	Drift eliminators
			DRI 114 & 214: Unit #1 Clean Water Cooling Tower	17,611 gpm	PM_{10}: TDS </= 1000 mg/L; Max drift of 0.0005%	Drift eliminators
LA-0246	Valero Refining – New Orleans, LLC, St. Charles Refinery	12/31/2010	Cooling Towers	45,000 gpm - 61,250 gpm	PM_{10}: 0.08 - 1.2 lb/hr	Drift eliminators

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (gpm)	Limitation	Control Method
GA-0142	Osceola Steel Co.	12/29/2010	Cooling Towers CT1, CT21, CT22, and CT23	NA	PM_{10}: 0.0005% mass flow rate; 1000 mg/L	Drift eliminators
FL-0323	Gainesville Regional Utility (GRU) Deerhaven	12/28/2010	Mechanical Draft Cooling Tower	78,000 gpm	PM_{10}: 0.0005% max drift	Drift eliminators
OH-0341	Nucor Steel Marion, Inc.	12/23/2010	Cooling Tower	NA	PM: 0.005% drift rate	Drift eliminators
NH-0018	Laidlaw Berlin Biopower, LLC	07/26/2010	Wet Cooling Tower	60,000 gpm	PM: 0.0005% drift rate	Drift eliminators
ID-0018	Idaho Power Company, Langley Gulch Power Plant	06/25/2010	Cooling Tower	63,200 gpm	NA	Drift eliminators
LA-0239	Consolidated Environmental Mgmt, Inc. Nucor Steel Louisiana	05/24/2010	Blast Furnace Cooling Tower, Iron Solidification Cooling Tower & Air Separation Plant Cooling Tower	NA	PM: TDS </= 1000 mg/L; Max drift of 0.0005%	Drift eliminators
TX-0552	Stark Power Generation II Holdings, LLC, Wolf Hollow Power Plant	03/03/2010	Cooling Tower	NA	PM: 0.0005% drift rate	Drift eliminators
TX-0551	Panda Sherman Power Station	02/03/2010	Cooling Tower	NA	PM: 0.0005% drift rate	Drift eliminators
TX-0553	Lindale Renewable Energy, LLC	01/08/2010	Cooling Tower	NA	PM: 0.0005% drift rate	Drift eliminators
NV-0050	MGM Mirage	11/30/2009	Cooling Towers	10,890 gpm	PM_{10}: 0.001% drift rate and TSD concentration is limited to 3,600 ppm	Drift eliminators

The TDS requirements in cooling towers are very case specific due to available water supplies (quality and quantity), costs of equipment, size and use of cooling towers, site development limitations, and regulations governing water use. Te source is proposing to install cooling towers utilizing existing water wells to avoid impacts to the White River through installation of a new cooling water intake structure. By utilizing the well water, we start at higher values of TDS in the source water compared to the River. By relaxing the TDS limit in the air permit, this allows the source to use less water from the wells, and reduce impacts to the White River in the discharge. This occurs because less water is used and consequentially, there is less mass of dissolved material that subsequently requires discharge to the river.

Finally, managing TDS to lower levels than the proposed 5,000 mg/L would be extremely ineffective as a way to control particulate from the source. For example, PM2.5 from the cooling towers at 5000 mg/L assuming 8760 annual hours of operation yields 0.022 tpy while running at 1000 mg/L would yield 0.004 tpy, a difference of 0.018 tpy.

The following has been proposed as BACT for $PM_{2.5}$ emissions from the proposed Cooling Tower (U-7):

Therefore, a 0.0005% drift (mist) eliminator system is proposed as BACT for $PM_{2.5}$ emissions from the Cooling Towers, identified as U-7.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM, OAQ has approved the proposed $PM_{2.5}$ BACT for the Cooling Tower, identified as U-7.

(a) The $PM_{2.5}$ emissions from the Cooling Tower, identified as U-7 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and maximum total dissolved solids (TDS) shall be less than or equal to 5000 mg/L.

(b) The $PM_{2.5}$ emissions from the Cooling Tower shall be less than 0.005 pounds per hour.

PM, PM_{10} and $PM_{2.5}$ BACT– Turbine Lube Oil Demister Vents

Step 1: Identify Potential Control Technologies

The organic PM, PM_{10} and $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. Generally, organic PM, PM_{10} and $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Mechanical Collectors (such as Cyclones or Multiclones);

(2) Wet Scrubbers;

(3) Electrostatic Precipitators (ESP); and

(4) Fabric Filter Dust Collectors (Baghouses).

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Add - on - Controls
The organic PM (PM_{10} and $PM_{2.5}$) emissions from this source result only from the small amount of turbine lube oil used. This emissions level is so low that it would not be feasible for any add-on controls such as cyclones, baghouses, ESPs or wet scrubbers to effectively further reduce emissions. For this reason, the above-listed add-on particulate controls are not considered feasible in this BACT analysis. There is no evidence that any of these add-on controls have ever been used to control organic PM emissions from lube oil demister vents.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of add-on controls is not a technically feasible option for the Turbine Lube Oil Demister Vents at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the organic PM emissions resulting from the Turbine Lube Oil Demister Vents.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by IPL Eagle Valley Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies and IDEM's PSD Permits.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method
Draft Permit No. 109-32471-00004 Proposed Limit	**IPL Eagle Valley Generating Station**	**Proposed**	**Turbine Lube Oil Demister Vent**	**--**	**None**	**Good Design and Operating Practices**
TX-0453	Bayport Energy Center LP	10/20/2003	Lube Oil Vent	NA	0.1 lb/hr; 0.2 tpy	None
TX-0374	BP Amoco Chemical Co., Chocolate Bayou Plant	03/24/2003	GT Lube Oil Vent for Cogen Trains 2 & 3	NA	0.05 lb/hr, each; 0.22 tpy, each	None

Proposal: **IPL Eagle Valley Generating Station** – **Martinsville, Indiana**
The following has been proposed as BACT for organic PM (PM_{10} and $PM_{2.5}$) emissions from the proposed Turbine Lube Oil Demister Vents:

The organic PM (PM_{10} and $PM_{2.5}$) emissions from the Turbine Lube Oil Demister Vents shall be the use of good design and operating practices.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for organic PM, PM_{10} and $PM_{2.5}$ emissions for the Turbine Lube Oil Demister Vents.

The organic PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents shall be the use of good design and operating practices.

GHGs BACT – Combined Cycle Combustion Turbines EU-1 - EU-2

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions (CO_2e).

(1) Carbon Capture and Storage (CCS);

(2) High Thermal Efficiency System Design;

(3) Use of low carbon emitting fuel; and

(4) Good combustion Turbine Design.

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Storage (CCS)

CCS consists of three (3) distinct unit operations: the separation and capture of CO_2 from the flue gas, pressurization of the captured CO_2 and transportation of the CO_2 as a fluid via pipeline, and injection and long-term storage (usually geologic).

(1) *Capture and Separation*

The capture technologies applicable for fossil fuel combustion include the following:

(i) Pre-combustion systems designed to separate CO_2 and hydrogen in the high pressure syngas typically produced at coal integrated gasification combined cycle power plants.
(ii) Post-combustion systems designed to separate CO_2 from the flue gas produced by the combustion process.
(iii) Oxy-combustion systems that use high-purity oxygen rather than air in the combustion process to produce a highly concentrated CO_2 stream.

Pre-combustion systems are not applicable to this facility, since they would fundamentally redefine the nature of the proposed source (natural gas as opposed to a coal IGCC plant). Both post- and oxy-combustion systems could be considered available, and both are currently in development as *demonstration projects* at coal-fired power plants using amine and ammonia capture systems to remove the CO_2 from the flue gas. These capture systems are associated with very high energy penalties and still considered to be innovative and *not yet commercially available for this source*.

There are several technologies at various stages of development with the potential to separate and capture CO_2. Some have been demonstrated at the pilot scale, while others are at the bench-top or laboratory stage of development. Most of the existing applications, and those in the planning stage, are designed to control CO_2 from the combustion of fossil fuels, primarily coal and natural gas. US EPA considers municipal solid waste to be a solid biomass fuel that can be co-fired with fossil fuels to reduce the CO_2 emissions from boilers (EPA, 2010). Several demonstration projects are being supported through the U.S. Department of Energy's Clean Coal Power Initiative, but these facilities will exclusively burn coal (Interagency Task Force, 2010).

(2) Sequestration

Carbon sequestration usually involves the injection of CO_2 into deep geological formations of porous rock that are capped by one or more nonporous layers of rock. Injected at high pressure, the CO_2 exists as a liquid that flows through the porous rock to fill the voids. Saline formations, exhausted oil and gas fields, and un-mineable coal seams are candidates for CO_2 storage. Also, CO_2 injected for enhanced oil recovery (EOR) projects can result in long-term sequestration depending on the geologic conditions. Other systems include liquid storage in the ocean, solid storage by reactions leading to the creation of carbonates, and terrestrial sequestration. The nearest sequestration site in the Midwest is located in Decatur, Illinois adjacent to an ethanol plant owned by Archer Daniels Midland, Inc. This site (operated by the Midwest Geologic Sequestration Consortium) is currently exclusively sequestering CO_2 from this ADM facility. This was being accomplished as a demonstration or pilot study and has been successful at current levels of sequestration. It is worthwhile to point out that the fermentation tanks of an ethanol plant already produce a highly concentrated CO_2 waste-stream and at much lower volumes than a nominal 656 MW natural gas-fired power plant.

(3) Transportation

As noted above, the nearest sequestration site is located in Decatur, IL at the Midwest Geologic Sequestration Consortium well adjacent to the Archer Daniels Midland Company's ethanol plant location (4666 E Faries Parkway # 1, Decatur, IL), which is more than 150 miles from the EVGS site. The intervening terrain would also make pipeline construction challenging: 3 major river crossings (West Fork White River, Wabash River, and the Vermilion River), crossing or going around Lake Decatur in Illinois (still necessitating a crossing of the Sangamon River which forms Lake Decatur), crossing two major interstates (I-70 in Indiana and I-57 in Illinois) and several smaller streams and rivers (including the Eel River in Indiana). There is no existing right-of-way available for such a pipeline, so a major land acquisition process would need to be established. Furthermore, this would be an interstate pipeline so lengthy federal environmental clearances would be necessary.

One additional option would be to construct a pipeline to transport CO_2 from the proposed project site to Rockville, Indiana where the proposed Indiana Gasification facility might be constructed. This option is not available to the source today, and may never be. As part of Indiana Gasification's business plan, they plan to sell a portion of their CO_2 emissions to a pipeline company (Denbury Resources, Inc.) and to oil companies in Texas and Louisiana who would use the CO_2 for enhanced oil recovery (EOR). This pipeline would also be approximately 150 miles long to get to the Rockport location and face many of the same hurdles as the Decatur, IL pipeline option. However, in order for this option to be feasible, the proposed and existing infrastructure would have to have been designed and constructed with the additional CO_2 in mind. It has not and a lot of the infrastructure is already in the ground in Texas. In order to accommodate the additional material flows, the pipeline company would need to expand existing infrastructure, redesign proposed infrastructure, and move forward with construction. This pipeline has not been constructed yet. The IPL project will generate approximately 2.65 million tons of CO_2 annually compared to Indiana Gasification's approximately 6 million tons for pipeline shipment. Therefore, the infrastructure would need to be able to accommodate approximately 44% more material. Furthermore, it is unknown whether there is sufficient market available in the region to purchase or even utilize these emissions. For these reasons discussed above, this option is not discussed further since the Decatur, IL sequestration site has fewer unknowns associated with it.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a carbon capture and storage (CCS) is not a technically feasible option for the combined cycle combustion turbine at this source.

High Thermal Efficiency System Design

Increased energy efficiency is a potential means of reducing GHG emissions and has also been considered as a potential control technology for GHG emissions from the proposed project. There are generally two types of energy efficiency improvement categories. The first category consists of technologies, process improvements, or other means of increasing the energy efficiency of the new source. Increased energy efficiency of the new source will result in less quantity of fuel combusted per unit of output. In the case of a combined-cycle facility designed purely for electricity generation, the unit of output would be kilowatt-hours of electrical output. In the case of an auxiliary boiler, the output would be in thousand pounds of steam produced. Emergency diesel engine outputs are measured in horsepower or in the case of an emergency diesel engine generator in kW-hr. For a process heater such as the proposed natural gas dew point heater, there is no applicable measurable output. Reciprocating engine efficiency can be inferred from the amount of fuel combusted and the stack exit temperature and flow rate.

The second category of energy efficiency improvements consists of technologies, process improvement, or other means of improving the amount of energy that is generated or used on the site. This second category does not look at the direct GHG emissions from the new source (which was evaluated in the first category of energy efficiency options) but looks at other facility processes or ancillary equipment that could reduce the amount of energy consumed to produce the equivalent output. Potential technologies included in this category may include increasing the efficiency of process equipment such as a heat exchangers, fans, pumps, etc., as well increasing the energy efficiency of ancillary equipment such as standalone emergency generators, firewater pumps, hot water heaters, lighting, etc. US EPA does not recommend an individual evaluation of all energy efficiency options in this second category due to the extremely large number of options. Rather, US EPA recommends new facilities evaluate their overall energy efficient technologies against a high-level performance facility in the industry to demonstrate that the facility will achieve comparable levels of energy efficiency. The proposed combined cycle project is being designed specifically to be a highly fuel efficient generation plant in keeping with IPL's criterion of providing low-cost power to its customers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a high thermal efficiency system design is a technically feasible option for the combined cycle combustion turbine at this source.

Use of Low Carbon Emitting Fuels
Carbon dioxide is produced as a combustion product of any carbon containing fuel. All fossil fuels contain varying amounts of fuel bound carbon that is converted during the combustion process to produce CO and CO_2. The use of gaseous fuels such as natural gas compared to the use of higher carbon-containing fuels such as coal, pet-coke or fuel oils (residual or distillate) is a potentially feasible alternative to reduce the generation of CO_2 emissions from combustion turbines.

Natural gas combustion results in significantly lower GHG emissions than coal combustion (117 lb/MMBTU versus 210 lb/MMBTU). The use of lower carbon containing fuels in combustion turbines, pending the definition of the source, is an effective means to reduce the generation of CO_2 during the combustion process.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a low carbon emitting fuel is a technically feasible option for the combined cycle combustion turbine at this source.

Combustion Turbine Design
Available technologies considered for CTs focus on energy efficient facility design inherent to combined cycle technology. An emissions reduction strategy focused on energy efficiency options primarily focuses on optimizing the thermal efficiency of the generating facility such that it would require less fossil fuel for a given output, resulting ultimately in lower emissions of GHGs.

The designers of such systems use sophisticated computer models such as Thermoflow's GT Master to optimize the efficiency and generation capability of the system. This iterative analysis is done much more effectively by computer than could previously be accomplished by hand calculations. The use of this tool optimizes the heat rate (efficiency) of the proposed system over the entire range of operating design conditions of the facility. Finally, the source has a real and present economic incentive to design and operate the proposed generation facility as efficiently as practicable. In a brand new power plant, being designed from the ground up to achieve high efficiency (so as to produce least cost power from the minimum amount of purchased fossil fuel), substantial further "efficiency improvement projects" do not exist in the same sense that they might at an older, existing power plant.

More Efficient EGU
Maximizing EGU efficiency is an alternative available to reduce the consumption of fuel required to generate a fixed amount of output. The largest efficiency losses for a combustion turbine are related to exhaust heat. In a combined cycle system, this exhaust heat is recaptured in the

HRSG, and this is the fundamental technology that provides combined cycle technology with among the highest efficiency of any fossil fuel-fired power plant technology. In a combined cycle application, all of the components work together to achieve high system efficiency. Any increase in energy efficiency within the operation of the system yields reductions in the generation of CO_2 emissions on a per unit output basis. US EPA guidance (PSD and Title V Permitting Guidance for Greenhouse Gases, November 2010) evaluated the availability of high efficiency combustion turbine combined cycle systems with recognized thermal efficiencies in the range of 50 to over 56%. That summary addressed applications where an increased efficiency was achieved via design; the very technology that will be employed by the source. The source is proposing to install a state-of-the-art combustion turbine and heat recovery steam generator as part of this project within the case-specific features and operational parameters of the proposed project.

Combustion Air Cooling
A common method utilized to increase the electrical output of combustion turbines is to cool the combustion air during summer months prior to entering the combustion turbine. Cooling the combustion air via heat exchange systems maximizes the expansion of the air molecules and enhances the work these expanding gases perform on the turbine blades and hence higher amounts of electricity. The Hyperion Energy Center Best Available Control Technology (BACT) Analysis for Emissions of Carbon Dioxide, March 2009, claimed that achievable reductions in fuel usage and CO_2 emissions could be in the range of 10–15% for their project. In any event, this technology has no impact on turbine performance or BACT Limits on any but the hottest summer day.

Cogeneration / CHP as a CO2 Reduction Technique
Combined Heat and Power (CHP) is a technique involving the operation of a combustion system to generate heat for electric power generation as well as provide thermal energy to a process. The electric power is distributed for use, while thermal energy is used locally to support heating systems or industrial processes. A CHP system allows for the use of energy in the form of heat to provide thermal energy that would otherwise be lost in cooling water for a traditional EGU. For combustion turbine systems, the more likely CHP technique would be to provide space heating for nearby buildings or to provide makeup heat to nearby coal-fired EGUs (likely application for power plants with CT and coal-fired EGUs onsite). The use of this otherwise lost heat would thereby improve the overall efficiency of the EGU or process and subsequently reduce overall CO2 emissions, on an equivalent basis.

The use of a CHP system provides an opportunity to extract additional energy from heat otherwise lost in a traditional EGU. This type of system however does require the removal of steam from the steam turbine, which would thus reduce the magnitude of electric power generation recognized in the CHP. This electrical energy is instead transformed to thermal energy for use on a more local basis. The advantage to a CHP system is the net improvement of overall fuel efficiency compared to a traditional EGU operation.

For a CHP system to be beneficial there must be a local need for thermal energy as thermal energy cannot be effectively transported over extended distances.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified is:

(1) High Thermal Efficiency Design

(2) Use of low emitting carbon fuel

Step 4: Evaluate the Most Effective Controls and Document the Results

The source proposes the exclusive use of pipeline quality natural gas, which is the lowest carbon fossil fuel, resulting in reduced GHG emissions. IPL also proposes to procure, install and operate a high efficiency, low heat rate combined cycle generation facility. The expected net heat rate for the system operating at full load with duct firing is not more than 7,750 Btu/kW-hr (HHV-net), which is consistent with best design practices of other similar facilities. This figure is based upon a reasonable margin of compliance (total 12.8%) for the equipment including a 3.3% design margin, reflecting the possibility that the constructed facility may not achieve the design heat rate, a 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls, as well as a 3.5% degradation margin reflecting the variability in operation of auxiliary plant equipment (e.g. the cooling towers) due to use over time.

As stated previously, there is no meaningful GHG BACT technology for these small, intermittent sources contained in any PSD permits for similar combined cycle power plants beyond good engineering practice and the use of 40 CFR 98 emission factors. This annual mass emission limit does not include potential fugitive emissions of SF_6 and CH_4 from the facility piping and components. Individual BACT requirements for these fugitive emissions are proposed later.

The GHG BACT emissions from the combined cycle combustion turbines shall not exceed 2,649,570 tons, on a carbon dioxide equivalent basis (CO2e) in any consecutive rolling 12-month period.

Methane and nitrous oxide emissions from the CTs shall be calculated in accordance with the methodology and emission factors noted in 40 CFR 98, Subpart D. The source proposes to install a CO_2 CEMS as specified under 40 CFR 75, to monitor CO_2 emissions from the CT/HRSG units and record those emissions hourly, track fuel usage in all the combustion sources, and calculate a consecutive rolling 12-month average CO_2e emissions. These emissions are proposed to be included in the facility quarterly reports.

The following has been proposed as BACT for GHG emissions from the proposed combined cycle combustion turbines:

(1) The net heat rate shall not exceed 7,750 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(2) The total CO_{2e} emissions for combined cycle combustion turbines shall be limited to less than 2,649,570 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for the GHG for the combined cycle combustion turbines:

(1) The net heat rate shall not exceed 7,750 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(2) The total CO_2e emissions for combined cycle combustion turbines shall be limited to less than 2,649,570 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

GHGs BACT – Auxiliary Boiler EU-3

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

(1) Operating and Maintenance (O&M) Practices;

(2) Efficient Burner Design;

(3) Improved Combustion Measures: Combustion Tuning;

(4) Improved Combustion Measures: Optimization & Digital Control System;

(5) Air Preheat & Economizers;

(6) Boiler Insulation;

(7) Condensation Return System; and

(8) Steam Line Maintenance.

Step 2: Eliminate Technically Infeasible Options

Operating and Maintenance (O&M) Practices
Boiler efficiency decreases over time; however, the rate of deterioration can be curbed by proper Operating and Maintenance (O&M) practices. A well operated and maintained plant will experience less deterioration of boiler efficiency.

Deterioration results in higher heat rate, CO_2 emissions, and operating costs; in lower reliability; and in some cases, reduced output. After a few years of neglect, it may reach the point where significant investment is required to rehabilitate the plant and bring it as close as possible to the design performance.

Rehabilitation may focus on life extension and reliability improvement of the plant or may include additional measures that improve plant efficiency, occasionally above the original design efficiency. The efficiency can be improved by retrofitting combustion control technologies such as heat recovery systems, control technology, and upgraded burners.

Additional GHG reductions can be achieved through energy improvements in the steam/hot water distribution system, the boiler auxiliaries, or in process efficiency improvements.

Operation and maintenance according to the manufacturer's emission-related instructions or per a facility-developed maintenance plan (in a manner consistent with safety and good air pollution control practices for minimizing emissions) will prevent generation of additional GHG emissions due to efficiency losses over the lifetime of each piece of combustion equipment.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Operating and Maintenance (O&M) practices is a technically feasible option for the Auxiliary Boiler at this source.

Efficient Burner Design

New efficient burner designs for all types of boilers and fuels are commercially available to help minimize fuel combustion and GHG emissions. Burners with single and multiple fuel capability, low- and ultra low-NO_X models, and sizes ranging from very small to very large are widely deployed in industry. Further, the burner size and turndown capability (i.e., ability to operate and/or efficiency of operation at less than full load) are also key aspects of burner design as they will impact the losses associated with inefficient low load and on/off cycling duty. A higher turndown ratio reduces burner startups, provides better load control, saves wear-and-tear on the burner, and reduces purge-air requirements, all resulting in better overall efficiency. Therefore, site-specific conditions and objectives may favor one model over the other. The emission reduction is up to a 6% reduction of CO_2 emissions.

Efficient burner designs will be employed, taking into account the size, fuel flexibility, operating loads, and other site specific conditions and objectives for each piece of combustion equipment.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of efficient burner designs is a technically feasible option for the Auxiliary Boiler at this source.

Improved Combustion Measures: Combustion Tuning

Tuning of the combustion system requires a visual check by an experienced boiler engineer to ensure that everything is in good working condition and set according to the manufacturer's recommendations or the optimum settings developed for the particular boiler. Simple parametric testing may be required, which may involve changes in the key control variables of the combustion system and observation of key parameters such as CO emissions, steam outlet conditions, flue gas outlet (stack) temperature, and NO_X emissions.
Up to a 3% reduction in CO_2 emissions

As part of the O&M practices, combustion tuning of boilers will be conducted on an as-needed basis to address any decreases in boiler efficiency over time.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Improved Combustion Measures: Combustion Tuning is a technically feasible option for the Auxiliary Boiler at this source.

Improved Combustion Measures: Optimization & Digital Control System

Optimization can be accomplished through parametric testing, analysis of the results, parameter estimation, periodic testing, and/or manual tuning. Software-based optimization systems may be cost effective for large boilers.

Digital control systems are generally necessary to achieve the greatest improvement in performance through tuning and optimization. Temperature sensors, oxygen monitors, oxygen trim controls, and other instrumentation may be required to maximize boiler efficiency.

The addition of optimization systems, modern control systems, and instrumentation has resulted in efficiency improvements of 0.5 to 5%.

The selected package boilers will be equipped with oxygen trim controls and oxygen analyzers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Operating and Maintenance (O&M) practices is a technically feasible option for the Auxiliary Boiler at this source.

Air Preheat & Economizers

Energy efficiency can be increased by using waste heat gas recovery systems to capture and utilize heat in the flue gas. The most commonly used waste heat recovery methods are preheating combustion air and water heating via economizer. Economizers and air preheaters often occupy a substantial physical footprint.

There are two general types of air preheaters: recuperators and regenerators. Recuperators are gas-to-gas heat exchangers usually placed on the boiler stack. Internal tubes or plates transfer heat from the outgoing exhaust to the incoming combustion air. Regenerators include two or more separate heat storage sections. The hot flue gas heats the heating plates which in turn heat the incoming combustion air. General benefits include improved efficiency and faster startup. Efficiency typically increases by 1% for each 40°F reduction in flue gas temperature.

In an economizer, tubular heat transfer surfaces preheat the boiler feedwater before it enters the steam drum or furnace surfaces. Economizers also reduce the potential of thermal shock and strong water temperature fluctuations as the feedwater enters the drum or waterwalls. Economizers are typically installed on larger units. Air preheaters typically increase efficiency by 1% for each 40 °F reduction in flue gas temperature. Economizers typically operate at a thermal efficiency of 5%.

Air preheaters are not widely used for industrial, commercial, or institutional boilers as the resulting increases in combustion temperature contribute to elevated emissions of NO_X. The auxiliary boiler will be equipped with an economizer.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Improved Combustion Measures: Optimization & Digital Control System is a technically feasible option for the Auxiliary Boiler at this source.

Boiler Insulation

Significant heat losses can occur through the boiler shell. Proper insulation is used to minimize such losses. The refractory material lining inside the boiler is the primary insulating material, but properly applied insulation on the outer boiler surface can also reduce heat losses.

Insulation is categorized as either mass or reflective type depending on whether it is intended to reduce conductive or radiative heat transmission, respectively. Radiation losses tend to increase with decreasing load and can be as high as 7% for small units or for larger units operating at reduced loads. The Thermal Insulation Manufacturers' Association provides guidance for determining the optimum insulation thickness for various applications. Up to 7%, varying by boiler load. Energy efficient refractory will be installed.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of boiler insulation is a technically feasible option for the Auxiliary Boiler at this source.

Condensation Return System

Hot condensate that is not returned to the boiler represents a corresponding loss of energy. Other benefits associated with an efficient condensate return system include reduced make-up water usage, water related treatment costs, boiler blowdown, and disposal costs. Energy savings originate from the fact that most condensate is returned at relatively high temperatures (typically 130 to 225 °F) compared to the cold makeup water (50 to 60 °F) that must be heated, but must also account for the “steam flash loss” - the amount of saturated condensate that flashes off to steam when reduced to a lower pressure. Operation of the return condensate system depends on the specific boiler and water/condensate quality. Site-specific conditions and economic considerations must be addressed to determine whether it would be applicable, and, therefore, it is necessary to consider its viability on a case-by-case basis.

A further improvement on recovering the available energy of the condensate may be to use a heat exchanger (vent condenser) where the flashing steam is typically vented. Site-specific evaluation is necessary before determining the viability of this approach.

Expected efficiency improvements vary based on condensate temperature and % recovery. The selected package boilers will be equipped with a condensate return system.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of condensation return system is a technically feasible option for the Auxiliary Boiler at this source.

Steam Line Maintenance

Heat losses through uninsulated lines and fittings can be significant. For example, 250 ft of uninsulated, 4-inch line with 300 psig steam would yield 2,800 MMBtu/yr, the equivalent of about 0.3 to 1.2% heat loss for boiler sizes between 25 and 100 MMBtu/hr. Similarly, the penalties for leaky valves/traps can represent measurable losses. General experience suggests that steam systems that do not include steam trap maintenance over a period of 3 to 5 years can result in 15 - 30% steam trap failures. Leaking traps should account for less than 5% of the trap population at plants with regular inspection and maintenance programs for steam traps.

Energy audits and maintenance procedures should highlight common maintenance items such as uninsulated steam distribution and condensate return lines and other fittings. Ensuring that all steam/condensate lines are properly insulated will yield measurable efficiency gains. Common practice suggests that surfaces over 120 °F (steam and condensate return piping, fittings) should be insulated. Insulating jackets are available for valves, traps, flanges and other fittings. Leaky steam traps should be fixed as they represent another potentially significant source of wasted energy. Energy efficiency gains and cost depend on length and type of insulation required. Steam and hot water lines will be insulated. As part of the O&M practices, the steam system components and insulation will be periodically inspected for leaks.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of stream line maintenance is a technically feasible option for the Auxiliary Boiler at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, the remaining control technologies may be ranked as follows for controlling GHG emissions from the Auxiliary Boiler.

(1) Boiler Insulation; (7% CO_2 Reduction)

(2) Efficient Burner Design (6% CO_2 Reduction)

(3) Air Preheat & Economizers; (5% CO_2 Reduction)

(4) Improved Combustion Measures: Optimization & Digital Control System; (0.5-5% CO_2 Reduction)

(5) Improved Combustion Measures: Combustion Tuning; (3% CO_2 Reduction)

(6) Steam Line Maintenance;

(7) Condensation Return System;

(8) Operating and Maintenance (O&M) Practices;

Step 4: Evaluate the Most Effective Controls and Document the Results

Operation and maintenance according to the manufacturer's emission-related instructions or per a facility-developed maintenance plan (in a manner consistent with safety and good air pollution control practices for minimizing emissions) will prevent generation of additional GHG emissions due to efficiency losses over the lifetime of each piece of combustion equipment. Efficient burner designs will be employed, taking into account the size, fuel flexibility, operating loads, and other site specific conditions and objectives for each piece of combustion equipment. As part of the O&M practices, the air handling systems for each boiler will be periodically inspected for leaks and combustion tuning of boilers will be conducted on an as-needed basis to address any decreases in boiler efficiency over time.

The GHG BACT emissions from the auxiliary boiler shall not exceed 40,369 tons, on a carbon dioxide equivalent basis (CO2e) in any consecutive rolling 12-month period.

The proposed natural gas boilers are stand-by, auxiliary units that are not intended to operate a significant number of hours.

The following has been proposed as BACT for GHG emissions from the proposed auxiliary boiler:

(1) Operating and Maintenance (O&M) Practices;

(2) Combustion Turning;

(3) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(4) The boiler will be equipped with an economizer;

(5) The boiler will be equipped with a condensate return system (recovery);

(6) Steam and hot lines will be insulated; and

(7) Boiler designed for 80% thermal efficiency (HHV).

(8) The total CO_2e emissions for Auxiliary Boiler shall be limited to less than 40,369 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for the GHG for the Auxiliary Boiler:

(1) Operating and Maintenance (O&M) Practices;

(2) Combustion Turning;

(3) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(4) The boiler will be equipped with an economizer;

(5) The boiler will be equipped with a condensate return system (recovery);

(6) Steam and hot lines will be insulated; and

(7) Boiler designed for 80% thermal efficiency (HHV).

(8) The total CO_2e emissions for Auxiliary Boiler shall be limited to less than 40,639 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Greenhouse Gases (GHG) BACT – Dew Point Heater (EU-4)

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

GHG control possibilities identified and addressed in this BACT analysis for the dew point heater are as follows:

(1) The use of natural gas fuel, a low-carbon fuel source.
(2) Good engineering design and good combustion practices
(3) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options

Natural Gas Use
This heater is proposed to use only natural gas. As a low-carbon fuel source, this will minimize greenhouse gas emissions.

Good Engineering Design and Good Combustion Practices
The combustion of natural gas is inherently efficient, and good engineering design of the burner will assure efficient combustion.

Beyond the use of good engineering design and the use of clean natural gas as previously mentioned, no additional applicable good combustion practices have been identified.

Carbon Capture
Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The small combustion sources such as the dew point heater do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.

The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, this Project miscellaneous combustion source only uses 20.8 MMBtu/hr. As such it is two orders of magnitude smaller than EPA's boiler example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the dew point heater is not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the dew point heater at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified are;

(1) The good engineering design and Combustion Practices; and

(2) The use of only natural gas.

Step 4: Evaluate the Most Effective Controls and Document the Results

The GHG BACT emissions from the Dew Point Heater shall not exceed 10,659 tons, on a carbon dioxide equivalent basis (CO2e) in any consecutive rolling 12-month period.

The following has been proposed as BACT for GHG from the proposed Dew Point Heater (EU-4):

The only feasible, applicable and available control technologies identified are;

(1) The good engineering design and Combustion Practices; and

(2) The use of only natural gas.

(3) The total CO_2e emissions for Dew Point Heater shall be limited to less than 10,659 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHGs for the dew Point Heater, identified as EU-4.

(1) The good engineering design and Combustion Practices; and

(2) The use of only natural gas.

(3) The total CO_2e emissions for Dew Point Heater shall be limited to less than 10,659 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

GHGs BACT – Emergency Generator

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from diesel engines. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

Distillate fuel oil is used because it is an independent source of fuel not related to the operation of the facility. As such, it is the most reliable fuel source and its use in this application is fundamental to meeting power and water requirements in an emergency situation. For this reason, it is the most common fuel used for these types of emergency backup applications.

GHG control possibilities identified and addressed in this BACT analysis for these small engines are:

(1) Good engineering design and Fuel efficient design; and

(2) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options

Good Engineering Design and Fuel Efficient Design

The source will install engines meeting the latest efficiency and pollutant performance standards specified in NSPS Part 60 Subpart IIII and NESHAP Part 63 Subpart ZZZZ. These Diesel engines are built with automatic control of the air to fuel ratio that ensures that they operate when needed and meet the applicable standards.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good engineering design and Fuel efficient design is a technically feasible option for the Emergency generators at this source.

Carbon Capture

Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The source combustion sources such as the emergency engines do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option. The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, the source's Project miscellaneous combustion sources are an order of magnitude smaller than EPA's example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the emergency diesel engines is not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. Further, the emergency engines are intermittent sources, which would further increase the cost and difficulty of implementing any control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the Emergency generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technology identified to reduce greenhouse gases from the emergency generator engines is to utilize good engineering design and fuel efficient design.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following has been proposed as BACT for GHG emissions from the proposed Emergency generator engine: the selection and use of good engineering design and fuel efficient design.

This project includes one (1) distillate oil-fired emergency generator 1,826 HP KW standby emergency generator. This engine is required for safety reasons. The engine is expected to operate at 500 hours per year. That use is associated with assuring their readiness in an emergency. The emergency engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because they will combust distillate oil fuel. However, because their normal use is limited to routine maintenance, inspection and testing, their total emissions are very small (less than 650 tons CO_2e/yr).

The following has been proposed as BACT for GHG emissions from the proposed Emergency Generator:

(1) The use of a good engineering design.

(2) The use of Ultra-low sulfur diesel fuel

(3) The total CO_2e emissions for Emergency Diesel Generator shall be limited to less than 605 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Emergency Diesel Generator:

(1) The use of a good engineering design;

(2) The use of Ultra-low sulfur diesel fuel; and

(3) The total CO_2e emissions for Emergency Diesel Generator shall be limited to less than 605 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

GHGs BACT – Emergency Fire Pumps

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from diesel engines. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

Distillate fuel oil is used because it is an independent source of fuel not related to the operation of the facility. As such, it is the most reliable fuel source and its use in this application is fundamental to meeting power and water requirements in an emergency situation. For this reason, it is the most common fuel used for these types of emergency backup applications.

GHG control possibilities identified and addressed in this BACT analysis for these small engines are:

(1) Good engineering design and Fuel efficient design; and

(2) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options

Good Engineering Design and Fuel Efficient Design

The source will install engines meeting the latest efficiency and pollutant performance standards specified in NSPS Part 60 Subpart IIII and NESHAP Part 63 Subpart ZZZZ. These Diesel engines are built with automatic control of the air to fuel ratio that ensures that they operate when needed and meet the applicable standards.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good engineering design and Fuel efficient design is a technically feasible option for the Emergency Fire pump at this source.

Carbon Capture

Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The source combustion sources such as the emergency engines do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the

Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option. The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, the source's Project miscellaneous combustion sources are an order of magnitude smaller than EPA's example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the emergency diesel engines is not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. Further, the emergency engines are intermittent sources, which would further increase the cost and difficulty of implementing any control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the Emergency Fire pump at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technology identified to reduce greenhouse gases from the emergency fire pump engine is to utilize good engineering design and fuel efficient design.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following has been proposed as BACT for GHG emissions from the proposed Emergency Fire pump engine: the selection and use of good engineering design and fuel efficient design.

This project includes one distillate oil fired 500 HP standby emergency fire pump. This engine is required for safety reasons. The engine is expected to operate less than 500 hours per year. That use is associated with assuring their readiness in an emergency. This emergency diesel engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because they will combust distillate oil fuel. However, because their normal use is limited to routine maintenance, inspection and testing, their total emissions are very small (less than 200 tons CO_2e/yr).

The following has been proposed as BACT for GHG emissions from the proposed Emergency Fire Pump Engine:

(1) The use of a good engineering design.

(2) The use of Ultra-low sulfur diesel fuel.

(3) The total CO_2e emissions for Firewater Pump Engine shall be limited to less than 157.50 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Firewater Pump Engine:

(1) The use of a good engineering design.

(2) The use of Ultra-low sulfur diesel fuel.

(3) The total CO_2e emissions for Firewater Pump Engine shall be limited to less than 157.50 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

GHGs BACT – Circuit Breakers SF_6

Step 1: Identify Potential Control Technologies

GHG control possibilities identified and addressed in this BACT analysis for these small potential sources are:

(1) Fully Enclosed SF6 breaker.
(2) Alternative Dielectric Material.

Step 2: Eliminate Technically Infeasible Options

Pressurized and enclosed breakers
The use of fully enclosed circuit breakers with leak detection (low pressure alarm) is state-of-the-art for circuit breakers. A low pressure alarm is installed on each breaker to alert operators of a loss of SF_6 gas. Operators will investigate the cause of any alarm and take corrective measures to stop the leak if one exists.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of pressurized and enclosed breaker is a technically feasible option for the Circuit Breaker at this source.

Alternative Dielectric Material
There is no practical alternative to the use of SF_6 as the insulator and arc quenching substance in the circuit breakers the source is proposing to installed. The unique performance qualities of SF_6 breakers is further supported by the most recent report released by the EPA SF_6 Partnership, which states: “no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties.” Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications. While some progress has reportedly been made in medium- or low-voltage applications, most studies have concluded, “that there is no replacement gas immediately available to use as an SF_6 substitute” for high-voltage applications. Therefore, the use of a breaker that doesn’t contain SF_6 is judged as not feasible for this application.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Alternative Dielectric Material is not a technically feasible option for the Circuit Breaker at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) The use of totally enclosed and pressurized circuit breakers with a density alarm for leak detection.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following has been proposed as BACT for GHGs from the proposed Electric Circuit Breaker:

(1) The use of totally enclosed and pressurized circuit breakers with a design leak rate of 0.5% by weight and a density alarm for leak detection.

(2) The total SF_6 emissions for circuit breakers shall be limited to less than 59.80 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for GHGs for Electrical Circuit Breaker.

(1) The use of totally enclosed pressure system with a design leak rate of 0.5% by weight and a density alarm for leak detection.

(2) The total SF_6 emissions from all the circuit breakers shall not exceed 59.8 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Greenhouse Gases (GHG) BACT – Fugitive Equipment Leaks

Step 1: Identify Potential Control Technologies

The source estimates there will be a small amount of GHG emissions from piping component, precisely CH_4. These fugitive emissions are so small relative to the overall facility emissions and in an absolute sense that further control of fugitive emissions would have minimal additional benefit.

The GHG emissions from fugitive equipments leaks can be controlled by;

(a) Leakless Technology;

(b) Instrument Leak detection and repair (LDAR) programs; and

(c) Auditory, Visual, and Olfactory (AVO) Monitoring.

Step 2: Eliminate Technically Infeasible Options

Leakless Technology
Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Likewise, some technologies, such as bellows valves, cannot be repaired without a unit shutdown. Because natural gas is not considered highly toxic nor a hazardous material, this gas does not warrant the risk of unit shut down for repair, and therefore leakless valve technology for fuel lines is considered technically impracticable.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Leakless technology is not a technically feasible option for the fugitive equipment leaks at this source.

Instrument Leak Detection and Repair (LDAR) Programs
Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls. Some of the more stringent LDAR programs provide for 97% control credit for valves, flanges, and connectors.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Instrument Leak detection and repair (LDAR) programs is a technically feasible option for the fugitive equipment leaks at this source.

Auditory, Visual and Olfactory (AVO) Monitoring
As-observed AVO methods are generally somewhat less effective than instrument LDAR programs, since they are not conducted at specific intervals. However, since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Auditory, Visual, and Olfactory (AVO) Monitoring is a technically feasible option for the fugitive equipment leaks at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(a) Instrument Leak detection and repair (LDAR) programs; and

(b) Auditory, Visual, and Olfactory (AVO) Monitoring

Step 4: Evaluate the Most Effective Controls and Document the Results

Although instrument LDAR programs of piping fugitive emissions in natural gas lines may be somewhat more effective than as-observed AVO methods, these methods are not economically practicable for GHG control from components in fuel gas service. No other proposed or recently issued permits for natural gas CCCT installations have required an LDAR program. The incremental GHGs controlled by implementation of an LDAR program is approximately 1,442.9 tons CO_2e per year, or about 0.053% of the total project's proposed CO_2e annual emissions. This project will consist of approximately 1,852 various components and an LDAR annual cost per component would be approximately $16 per component for an annual cost of about $29,632. This corresponds to about $20.54 per ton of CO_2e reduction for this project. The LDAR program for methane leaks is considered economically impracticable for this project.

The following has been proposed as BACT for GHGs from the proposed Fugitives Equipment Leaks:

The BACT for fugitive GHG emissions is proposed to be use of Auditory, Visual, and Olfactory (AVO) Monitoring program for methane leaks with repairs to be made as soon as it is safe and practicable to do so.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), IDEM has established the following as BACT for GHG for Fugitives Equipment Leaks.

The BACT for fugitive GHG emissions shall be use of Auditory, Visual, and Olfactory (AVO) Monitoring program for methane leaks.

Best Available Control Technology during Startup and Shutdown for the Combustion Turbines, identified as EU1-EU2.

(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves consecutive CEMS data points in compliance with the primary BACT limits.

(b) Steady-state operating condition shall be defined as the period of time that the combustion turbine is operating in dry low NOx (premix) mode and in compliance with the primary BACT limit.

(c) A shutdown is defined as operation beginning when the combustion turbine exits dry low-NOx (premix) mode and ending with termination of continuous fuel flow to each turbine.

(d) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(e) Unit Offline is represented by the Unit on-line Time being 0.

(f) The following records shall be kept by the source:

(1) Number of minutes in each hour that the unit is in startup mode.

(2) Number of minutes in each hour that the unit is in shutdown mode.

(3) Records shall be maintained at any time the unit is off-line.

(g) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown

For CO and NO_X, the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCTs. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor. Therefore, the source proposes to use the cold start emission totals, per CCCT as a short-term limit during startup/shutdown events, as follows:

CO - 3,390 lb/event

NOx - 429 lb/event

(h) The NO_X emissions from the combined cycle combustion turbines stacks shall not exceed 68 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(i) The CO emissions from the combined cycle combustion turbines stacks shall not exceed 565 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(j) The VOC emissions from the combined cycle combustion turbines stacks shall not exceed 146 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

Cost Effectiveness Assessment for use of an Oxidation catalyst to Control CO Emissions from the 79.3 MMBtu/hr Auxiliary Boiler

Cost Item	Average Cost Factor		Cost ($s)	Basis of Costs
Direct Costs:				
Catalytic Oxidizer for Auxiliary Boiler (26,000 cfm)			**$ 1,366,000**	**EPA Cost Estimation Tool**
Instruments/controls	0.10		$ 136,600	EPA Cost Manual Table 2.8
Taxes	0.05		$ 68,300	EPA Cost Manual Table 2.8
Freight	0.05		$ 68,300	EPA Cost Manual Table 2.8
Base Price:			**$ 1,639,200**	
Installation costs, direct:				
Foundations/Supports	0.08		$ 131,136	EPA Cost Manual Table 2.8
Erection/handling	0.14		$ 229,488	
Electrical	0.04		$ 65,568	
Piping	0.02		$ 32,784	
Insulation	0.01		$ 16,392	
Painting	0.01		$ 16,392	
Total Installation Costs:			**$ 491,760**	
TOTAL DIRECT COSTS (Base Price + Installation)=			**$ 2,130,960**	
Installation costs, indirect:				
Engineering/supervision	0.10		$ 163,920	EPA Cost Manual Table 2.8
Construction/field expenses	0.05		$ 81,960	
Construction fee	0.10		$ 163,920	
Start-up	0.02		$ 32,784	
Performance Test	0.01		$ 16,392	
Contingencies	0.03		$ 49,176	
TOTAL INDIRECT COSTS=			**$ 508,152**	
TOTAL CAPITAL COSTS (Direct + Indirect)=			**$ 2,639,112**	
<u>Direct Operating Costs</u>:		**hours/year**		
Operator ($/HR X HRS/YR)	15.5	547.5	$ 8,486	EPA guidance - 0.5 hour per shift per device
Supervision(15% of labor)			$ 1,273	EPA Cost Manual
Operating Materials:				
Maintenance Labor	40	547.5	$ 21,900	EPA Guidance (.5 hour/shift/device)
Maitenance Materials (100% of labor)			$ 21,900	
Replacement parts (as required)	5% of equipment costs		$ 68,300	
Utilities:				
Electricity ($/KWHxKWH/yr)	$0.04/kw		$ 7,106	
Gas ($\$/10^3 ft^3 x\ 10^3/yr$)	$4/MMBtu		$ 78,325	
TOTAL DIRECT OPERATING COSTS (A)=			**$ 207,290**	
<u>Indirect operating (fixed) costs:</u>				
Overhead	60% of O & M labor/materials		$ 32,136	EPA Cost Manual
Property Tax	1% of capital costs		$ 26,391	
Insurance	1% of capital costs		$ 26,391	
Administration	2% of capital costs		$ 52,782	
Capital Recovery CRF=	0.13	(5.0% for 10 years)	$ 343,085	
TOTAL FIXED COSTS (B)=			**$ 480,785**	
TOTAL ANNUALIZED COSTS (A +B minus C)=			**$ 688,075**	
Uncontrolled CO Emissions Rate (tons/year) based on 79.3 MMBTU/hr NG Fired Aux Boiler operating 8760 hours/year			**28.5**	
Control System Efficiency based on 100% capture and 75% control			75.0%	
Controlled Emissions Rate (tons/year)=			7.13	
CO Controlled, tons/year			21.38	
Cost ($/ton)=			**$32,191**	
"EPA Air Pollution Control Cost Manual, Sixth Edition", EPA-452-02-001, January 2002.				

Cost Effectiveness Assessment for use of an Oxidation catalyst to Control VOC Emissions from the 79.3 MMBtu/hr Auxiliary Boiler

Cost Item	Average Cost Factor		Cost ($s)	Basis of Costs
Direct Costs:				
Catalytic Oxidizer for Auxiliary Boiler (26,000 cfm)			**$ 1,366,000**	**EPA Cost Estimation Tool**
Instruments/controls	0.10		$ 136,600	EPA Cost Manual Table 2.8
Taxes	0.05		$ 68,300	EPA Cost Manual Table 2.8
Freight	0.05		$ 68,300	EPA Cost Manual Table 2.8
Base Price:			**$ 1,639,200**	
Installation costs, direct:				
Foundations/Supports	0.08		$ 131,136	
Erection/handling	0.14		$ 229,488	
Electrical	0.04		$ 65,568	
Piping	0.02		$ 32,784	EPA Cost Manual Table 2.8
Insulation	0.01		$ 16,392	
Painting	0.01		$ 16,392	
Total Installation Costs:			**$ 491,760**	
TOTAL DIRECT COSTS (Base Price + Installation)=			**$ 2,130,960**	
Installation costs, indirect:				
Engineering/supervision	0.10		$ 163,920	
Construction/field expenses	0.05		$ 81,960	
Construction fee	0.10		$ 163,920	EPA Cost Manual Table 2.8
Start-up	0.02		$ 32,784	
Performance Test	0.01		$ 16,392	
Contingencies	0.03		$ 49,176	
TOTAL INDIRECT COSTS=			**$ 508,152**	
TOTAL CAPITAL COSTS (Direct + Indirect)=			**$ 2,639,112**	
Direct Operating Costs:		**hours/year**		
Operator ($/HR X HRS/YR)	15.5	547.5	$ 8,486	EPA guidance - 0.5 hour per shift per device
Supervision(15% of labor)			$ 1,273	EPA Cost Manual
Operating Materials:				
Maintenance Labor	40	547.5	$ 21,900	EPA Guidance (.5 hour/shift/device)
Maitenance Materials (100% of labor)			$ 21,900	
Replacement parts (as required)	5% of equipment costs		$ 68,300	
Utilities:				
Electricity ($/KWHxKWH/yr)	$0.04/kw		$ 7,106	
Gas ($/$10^3$ft^{3}x 10^3/yr)	$4/MMBtu		$ 78,325	
TOTAL DIRECT OPERATING COSTS (A)=			**$ 207,290**	
Indirect operating (fixed) costs:				
Overhead	60% of O & M labor/materials		$ 32,136	
Property Tax	1% of capital costs		$ 26,391	
Insurance	1% of capital costs		$ 26,391	EPA Cost Manual
Administration	2% of capital costs		$ 52,782	
Capital Recovery CRF=	0.13	(5.0% for 10 years)	$ 343,085	
TOTAL FIXED COSTS (B)=			**$ 480,785**	
TOTAL ANNUALIZED COSTS (A +B minus C)=			**$ 688,075**	
Uncontrolled VOC Emissions Rate (tons/year) based on 79.3 MMBTU/hr NG Fired Aux Boiler operating 8760 hours/year			**1.8**	
Control System Efficiency based on 100% capture and 75% control			75.0%	
Controlled Emissions Rate (tons/year)=			0.45	
VOC Controlled, tons/year			1.35	
Cost ($/ton)=			**$509,685**	
"EPA Air Pollution Control Cost Manual, Sixth Edition", EPA-452-02-001, January 2002.				

Cost Effectiveness Assessment for use of an Oxidation catalyst to Control CO Emissions from the 20 MMBtu/hr Dew Point Heater

Cost Item	Average Cost Factor		Cost ($s)	Basis of Costs
Direct Costs:				
Catalytic Oxidizer for Dew Point Heater (6200 cfm)			**$ 475,000**	**EPA Cost Estimation Tool**
Instruments/controls	0.10		$ 47,500	EPA Cost Manual Table 2.8
Taxes	0.05		$ 23,750	EPA Cost Manual Table 2.8
Freight	0.05		$ 23,750	EPA Cost Manual Table 2.8
Base Price:			**$ 570,000**	
Installation costs, direct:				
Foundations/Supports	0.08		$ 45,600	EPA Cost Manual Table 2.8
Erection/handling	0.14		$ 79,800	
Electrical	0.04		$ 22,800	
Piping	0.02		$ 11,400	
Insulation	0.01		$ 5,700	
Painting	0.01		$ 5,700	
Total Installation Costs:			**$ 171,000**	
TOTAL DIRECT COSTS (Base Price + Installation)=			**$ 741,000**	
Installation costs, indirect:				
Engineering/supervision	0.10		$ 57,000	EPA Cost Manual Table 2.8
Construction/field expenses	0.05		$ 28,500	
Construction fee	0.10		$ 57,000	
Start-up	0.02		$ 11,400	
Performance Test	0.01		$ 5,700	
Contingencies	0.03		$ 17,100	
TOTAL INDIRECT COSTS=			**$ 176,700**	
TOTAL CAPITAL COSTS (Direct + Indirect)=			**$ 917,700**	
Direct Operating Costs:		**hours/year**		
Operator ($/HR X HRS/YR)	15.5	547.5	$ 8,486	EPA guidance - 0.5 hour per shift per device
Supervision(15% of labor)			$ 1,273	EPA Cost Manual
Operating Materials:				
Maintenance Labor	40	547.5	$ 21,900	EPA Guidance (.5 hour/shift/device)
Maitenance Materials (100% of labor)			$ 21,900	
Replacement parts (as required)	5% of equipment costs		$ 23,750	
Utilities:				
Electricity ($/KWHxKWH/yr)	$0.04/kw		$ 1,695	
Gas ($/$10^3$ft^{3}x 10^3/yr)	$4/MMBtu		$ 18,551	
TOTAL DIRECT OPERATING COSTS (A)=			**$ 97,554**	
Indirect operating (fixed) costs:				
Overhead	60% of O & M labor/materials		$ 32,136	EPA Cost Manual
Property Tax	1% of capital costs		$ 9,177	
Insurance	1% of capital costs		$ 9,177	
Administration	2% of capital costs		$ 18,354	
Capital Recovery CRF=	0.13	(5.0% for 10 years)	$ 119,301	
TOTAL FIXED COSTS (B)=			**$ 188,145**	
TOTAL ANNUALIZED COSTS (A +B minus C)=			**$ 285,699**	
Uncontrolled CO Emissions Rate (tons/year) based on 20 MMBTU/hr NG Fired Dew Point Heater operating 8760 hours/year			**7.5**	
Control System Efficiency based on 100% capture and 75% control			75.0%	
Controlled Emissions Rate (tons/year)=			1.87	
CO Controlled, tons/year			5.60	
Cost ($/ton)=			**$50,995**	
"EPA Air Pollution Control Cost Manual, Sixth Edition", EPA-452-02-001, January 2002.				

Cost Effectiveness Assessment for use of an Oxidation Catalyst to Control VOC Emissions from the 20 MMBtu/hr Dew Point Heater

Cost Item	Average Cost Factor		Cost ($s)	Basis of Costs
Direct Costs:				
Catalytic Oxidizer for Dew Point Heater (6200 cfm)			**$ 475,000**	**EPA Cost Estimation Tool**
Instruments/controls	0.10		$ 47,500	EPA Cost Manual Table 2.8
Taxes	0.05		$ 23,750	EPA Cost Manual Table 2.8
Freight	0.05		$ 23,750	EPA Cost Manual Table 2.8
Base Price:			**$ 570,000**	
Installation costs, direct:				
Foundations/Supports	0.08		$ 45,600	
Erection/handling	0.14		$ 79,800	
Electrical	0.04		$ 22,800	EPA Cost Manual Table 2.8
Piping	0.02		$ 11,400	
Insulation	0.01		$ 5,700	
Painting	0.01		$ 5,700	
Total Installation Costs:			**$ 171,000**	
TOTAL DIRECT COSTS (Base Price + Installation)=			**$ 741,000**	
Installation costs, indirect:				
Engineering/supervision	0.10		$ 57,000	
Construction/field expenses	0.05		$ 28,500	
Construction fee	0.10		$ 57,000	EPA Cost Manual Table 2.8
Start-up	0.02		$ 11,400	
Performance Test	0.01		$ 5,700	
Contingencies	0.03		$ 17,100	
TOTAL INDIRECT COSTS=			**$ 176,700**	
TOTAL CAPITAL COSTS (Direct + Indirect)=			**$ 917,700**	
<u>Direct Operating Costs</u>:		**hours/year**		
Operator ($/HR X HRS/YR)	15.5	547.5	$ 8,486	EPA guidance - 0.5 hour per shift per device
Supervision(15% of labor)			$ 1,273	EPA Cost Manual
Operating Materials:				
Maintenance Labor	40	547.5	$ 21,900	EPA Guidance (.5 hour/shift/device)
Maitenance Materials (100% of labor)			$ 21,900	
Replacement parts (as required)	5% of equipment costs		$ 23,750	
Utilities:				
Electricity ($/KWHxKWH/yr)	$0.04/kw		$ 1,695	
Gas ($/$10^3$ft^{3}x 10^3/yr)	$4/MMBtu		$ 18,551	
TOTAL DIRECT OPERATING COSTS (A)=			**$ 97,554**	
<u>Indirect operating (fixed) costs:</u>				
Overhead	60% of O & M labor/materials		$ 32,136	
Property Tax	1% of capital costs		$ 9,177	
Insurance	1% of capital costs		$ 9,177	EPA Cost Manual
Administration	2% of capital costs		$ 18,354	
Capital Recovery CRF=	0.13	(5.0% for 10 years)	$ 119,301	
TOTAL FIXED COSTS (B)=			**$ 188,145**	
TOTAL ANNUALIZED COSTS (A +B minus C)=			**$ 285,699**	
Uncontrolled VOC Emissions Rate (tons/year) based on 20 MMBTU/hr NG Fired Dew Point Heater operating 8760 hours/year			**0.48**	
Control System Efficiency based on 100% capture and 75% control			75.0%	
Controlled Emissions Rate (tons/year)=			0.12	
VOC Controlled, tons/year			0.36	
Cost ($/ton)=			**$793,608**	
"EPA Air Pollution Control Cost Manual, Sixth Edition", EPA-452-02-001, January 2002.				

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Governor

Thomas W. Easterly
Commissioner

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TO: Angelique Oliger
IPL - Eagle Valley
1 Monument Circle
Indianapolis, Indiana 46204

DATE: October 11, 2013

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

SUBJECT: Final Decision
PSD/Significant Source Modification to Part 70 Renewal
109-32471-00004

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
Bradley Scott, Responsible Official
Tom Rarick, Environmental Resources Management (ERM)
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 6/13/2013

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Governor
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Commissioner

October 11, 2013

TO: Morgan County Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: IPL - Eagle Valley
Permit Number: 109-32471-00004

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library.dot 6/13/2013

Mail Code 61-53

IDEM Staff	PWAY 10/11/2013 Indianapolis Power & Light Co. (IPL) Eagle Valley Gen.Stat 109-32471-00004 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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2		Bradley Scott Sr Dir - Plant Ops Indianapolis Power & Light Co. Eagle Valley Gener PO Box 436 / 6925 N SR 57 Petersburg IN 47567 *(RO CAATS)*									
3		Morgan County Commissioners 180 South Main Street Martinsville IN 46151 *(Local Official)*									
4		Martinsville City Council and Mayors Office P.O. Box 1415, 59 South Jefferson Street Martinsville IN 46151 *(Local Official)*									
5		Morgan Co Public Library 110 S Jefferson St Martinsville IN 46151-1999 *(Library)*									
6		Clayton D. & Patricia A. Arthur 5178 Brenda Boulvard Greenwood IN 46143 *(Affected Party)*									
7		Morgan County Health Department 180 S Main Street, Suite 252 Martinsville IN 46151-1988 *(Health Department)*									
8		David Jones 7977 N. Taylors Rd. Mooresville IN 46158 *(Affected Party)*									
9		Claudia Parker 6761 Centenary Rd. Mooresville IN 46158 *(Affected Party)*									
10		James Swails 6568 E. Rosebud Lane Mooresville IN 46158 *(Affected Party)*									
11		John Thurston 6548 E. Watson Mooresville IN 46158 *(Affected Party)*									
12		Bethany Town Council 7355 Bethany Park Martinsville IN 46151 *(Local Official)*									
13		Tom Rarick Environmental Resources Management (ERM) 11350 N Meridian Suite 320 Carmel IN 46032 (Consultant)									
14											
15											

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