INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

TO: Interested Parties / Applicant

DATE: March 27, 2013

RE: Purdue University / 157 - 32275 - 00012

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 13-17-3-4 and 326 IAC 2, this permit modification is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-7-3 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 Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) 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.

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

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

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

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

Enclosures
FNTV-PMOD.doc 3/27/08

IDEM

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March 27, 2013

Mr. Robin Mills Ridgway
Purdue University
HMMT, 201 Ahlers Dr
West Lafayette, IN 47906

Re: 157-32275-00012
Significant Permit Modification to
Part 70 Renewal No.: T 157-27313-00012

Dear Mr. Ridgway:

Purdue University was issued a Part 70 Operating Permit Renewal on August 27, 2010 for stationary boilers and other support facilities for the educational services operation, located at Purdue University. A letter requesting changes to this permit was received on September 5, 2012. Pursuant to the provisions of 326 IAC 2-7-12 a significant permit modification to this permit is hereby approved as described in the attached Technical Support Document.

Purdue University - West Lafayette on September 5, 2012, submitted an application relating to certain improvements to Purdue's Wade Utility Plant approved by the Board of Trustee. The improvements are the construction of a new combustion turbine with a heat recovery steam generator (CT/HRSG) and the conversion of Boiler 2 from coal to natural gas. The conversion of Boiler 2 to natural gas will have no impact on Purdue's energy production (since there is no change in capacity of Boiler 2 as a result of this project), however it will play an important role in Purdue's ability to meet Maximum Achievable Control Technology (MACT) standards for operations at the Wade Utility Plant.

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,

Tripurari Sinha

for Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Attachments:
Updated Permit
Technical Support Document
PTE Calculations

JB

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

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Indianapolis, Indiana 46204
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PART 70 OPERATING PERMIT
OFFICE OF AIR QUALITY

Purdue University
401 S. Grant Street
Freehafer Hall of Administrative Services
West Lafayette, Indiana 47907-2024

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

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

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

Operation Permit Renewal No.: T 157-27313-00012	
Issued by/ Original signed by: Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: August 27, 2010 Expiration Date: August 27, 2015

1st Administrative Amendment No. 157-30374-00012, issued on April 19, 2011.

Significant Permit Modification No.: 157-32275-00012	
Issued by: Tripurari Sinha for Matt Stuckey, Branch Chief Permits Branch Office of Air Quality	Issuance Date: March 27, 2013 Expiration Date: August 27, 2015

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in Conditions A.1 through A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

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

The Permittee owns and operates stationary boilers and other support facilities for the educational services operation, located at Purdue University.

Source Address:	401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, Indiana 47907-2024
General Source Phone Number:	(765) 496-6405
SIC Code:	8221
County Location:	Tippecanoe
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major, under PSD Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

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

This source consists of air emission units located on the main campus in West Lafayette, Indiana, and at research farms in the vicinity of 5675 West 600 North, West Lafayette, Indiana, for the Animal Sciences Research and Education Center.

A.3 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) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2013, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 75 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

After the startup of Boiler 7 this boiler, identified as Boiler 1 shall be decommissioned within one hundred and eighty (180) days:

(a1) One (1) spreader stoker coal fired boiler, identified as Boiler 1, with installation completed in 1960, with a nominal capacity of 281 MMBtu/hr, with a multi-cyclone collector and an electrostatic precipitator for particulate matter control, exhausting to stack WADE 01. Boiler 1 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

<u>After the fuel change from coal to natural gas in Boiler 2, the coal usage shall be discontinued in this boiler, identified as Boiler 2:</u>

(b1) One (1) spreader stoker coal fired boiler, identified as Boiler 2, with installation completed in 1967, with a nominal capacity of 274 MMBtu/hr, with a multi-cyclone collector and a multi-compartment baghouse for particulate matter control, exhausting to stack WADE 02. Boiler 2 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

<u>After fuel Change to Natural Gas:</u>

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in 2013, with a maximum heat input capacity of 315 MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

(c) One (1) natural gas and distillate fuel oil fired boiler, identified as Boiler 3, with installation started in 1973 or 1974 and completed in 1974, with a nominal capacity of 286 MMBtu/hr, exhausting to stack WADE 03. Boiler 3 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Under the Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 NSPS (40 CFR 60, Subpart D), Boiler 3 is considered an affected source.

(d) One (1) circulating fluidized bed coal fired boiler, identified as Boiler 5, with installation started in 1989 and completed in 1991, with a nominal capacity of 279 MMBtu/hr, with a baghouse for particulate matter control and limestone injection for sulfur dioxide control, combusting natural gas for ignition, exhausting to stack WADE 05. Boiler 5 has continuous emissions monitoring systems (CEMS) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM).

Under the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Db), Boiler 5 is considered an affected source.

(e) One (1) natural gas fired boiler, identified as Boiler 7, permitted in 2010, with a nominal capacity of 290 MMBtu/hr, exhausting to stack WADE 03. Boiler 7 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) for compliance with NSPS requirements.

Under the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Db), Boiler 7 is considered an affected source.

(f) One (1) coal storage and handling system identified as COAL Segment 1, installed in 1960, with a nominal capacity of 110 tons/hr, including: truck unloading station with two (2) hoppers; two (2) vibratory feeders; one (1) underground belt conveyor with a magnetic separator; and one (1) bucket elevator terminating at the top of Wade Utility Plant. Coal is fed to the bunkers for Boiler 1, Boiler 2, and to the pre-crusher ahead of the indoor storage silo for Boiler 5. Emissions from the Boiler 1 and Boiler 2 bunkers are controlled by a RotoClone for each of the two (2) bunkers. The bunker for Boiler 1 exhausts to stack CB1. The bunker for Boiler 2 exhausts to CB2. COAL Segment 1 has been retained as a backup system for COAL Segment 2.

(g) One (1) coal storage and handling system identified as COAL Segment 2, installed in 1996, with a nominal capacity of 107 tons/hr, including: truck unloading and two (2) in-ground hoppers, two (2) vibratory feeders; one (1) totally enclosed tubular conveyor identified as BC-1 equipped with a magnetic separator and with emissions controlled by a baghouse exhausting to stack CV1; one (1) transfer enclosure with one (1) coal sampler, with emissions controlled by a baghouse exhausting to stack CV2; and one (1) totally enclosed tubular conveyor identified as BC-2 terminating at the top of Wade Utility Plant, with emissions from the final transfer point controlled by a baghouse exhausting to stack CV3. Coal is fed to the bunkers for Boiler 1, Boiler 2, and to the pre-crusher ahead of the indoor storage silo for Boiler 5. Emissions from the Boiler 1 and Boiler 2 bunkers are controlled by a RotoClone for each of the two (2) bunkers. The bunker for Boiler 1 exhausts to stack CB1. The bunker for Boiler 2 exhausts to CB2.

(h) One (1) outdoor coal storage pile area identified as COAL PILE 1, permitted in 1960 and 1996, with particulate matter emissions exhausting to the atmosphere.

(i) One (1) coal preparation system for Boiler 5, with installation completed in 1991, with a nominal capacity of 12.68 tons/hr, including: one (1) enclosed 125 ton/hr Redler conveyor with one (1) enclosed pre-crusher (both serving in a back-up capacity), one (1) 150 ton/hr enclosed belt conveyor and pre-crusher with installation completed in 2009. Both lines feed into; one (1) coal storage bunker, two (2) weigh belt feeders; and two (2) enclosed crushers with emission directed to a baghouse exhausting to stack CB5.

Under the Standards of Performance for Coal Preparation Plants NSPS (40 CFR 60, Subpart Y), the coal preparation system for Boiler 5 including the crushers and COAL Segment 2 are considered affected sources.

(j) One (1) pneumatic ash handling system for fly ash and bottom ash from Boiler 1 and Boiler 2, identified as ASH Segment 1, with a nominal capacity of 14 tons per hour (ton/hr), installed in approximately 1960 and modified in 2002. Ash/particulate matter collected from the primary, secondary and tertiary (baghouse) collection units are transferred to the existing ash silo. Ash accumulated in this silo is removed via a water mixer into trucks. Particulate matter that passes through the tertiary (baghouse) filter is exhausted to stack ASH1 while air from the ash silo is directed to a final filter before exhausting to stack AB1. Ash/particulate matter is transported through the system by an electric vacuum pump.

(k) One (1) pneumatic ash handling system for fly ash and bottom ash from Boiler 5, identified as ASH Segment 2, installed in 1991 and modified in 2002, exhausting to stacks ASH5A and ASH5B, with a nominal capacity of 20 tons/hr, with dust from ash transfer to the storage silo controlled by primary and secondary separator with tertiary baghouse filter, ASH5D. Ash is transferred from the silo to trucks at a nominal capacity of 300 tons/hr; dust is controlled by water mix, or by use of a telescoping spout with air displaced from the truck directed through a “filter module” with five canister filters which exhaust to the atmosphere though a vent, ASH5C.

(l) Material handling for the limestone injection system for Boiler 5, including pneumatic conveyance system, identified as LC5, from truck to bulk storage in a silo outside, identified as LS1, or to a "day bin", identified as LI5, inside the plant at an offload rate of approximately 12.5 tons per hour (ton/hr); gravity fed from day bin into Boiler 5. Particulate emissions are controlled by a baghouse, identified as LSBH1, on the silo and filter cartridges, identified as BVLI5, on the day bin.

(m) One (1) natural gas fired dual chamber animal carcass incinerator, identified as ADDL, installed in 1991, with a nominal heat input capacity of 6.5 MMBtu/hr, with an 800 lb/hr waste capacity, exhausting to stack PUADDL1.

(n) One (1) no. 2 fuel oil fired Black Start electric generator, identified as BSG, with a nominal heat input capacity of 17.7 MMBtu/hr, exhausting through stack BSG-1, with a fuel limit of 113,000 gallons per year.

(o) Two (2) portable pumps powered by 350 HP no. 2 diesel fueled engines and mounted on tri-axle trailers, operated intermittently (approximately 500 hours per year each), used for pumping lagoon material to the spray irrigation system and to transfer material from one lagoon to another.

A.4 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 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) Boilers using the following fuels:

(1) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour, including three (3) natural gas fired Aviation Tech Building Boilers with low-NO_X combustion systems, installed in 2000, each with 2.8 MMBtu/hr heat input capacity, identified as AV Tech Boiler 1, AV Tech Boiler 2, and AV Tech Boiler 3.

(2) Propane or liquefied petroleum gas, or butane-fired combustion sources with heat input equal to or less than six million (6,000,000) Btu per hour.

(3) Fuel oil-fired combustion sources with heat input equal to or less than two million (2,000,000) Btu per hour and firing fuel containing less than five-tenths (0.5) percent sulfur by weight.

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

(c) Cleaners and solvents characterized as follows: [326 IAC 8-3]

(1) Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100°F) or;

(2) Having a vapor pressure equal to or less than 0.7 kPa; 5mm Hg; or 0.1 psi measured at 20°C (68°F); the use of which for all cleaners and solvents combined does not exceed 145 gallons per 12 months.

(d) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment. [326 IAC 6-3]

(e) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983. [326 IAC 6-3]

(f) Coal bunker and coal scale exhausts and associated dust collector vents. [326 IAC 6-3]

(g) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations. [326 IAC 6-3]

(h) Diesel and gasoline generators:

(1) One (1) BRK (nanotech) generator, with a nominal heat input rate of 3.4 MMBtu/hr.

(2) One (1) MJIS (biomed) generator, with a nominal heat input rate of 2.56 MMBtu/hr.

(3) Gasoline generators not exceeding one hundred ten (110) horsepower.

(4) Diesel generators not exceeding one thousand six hundred (1,600) horsepower.

(i) 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 (lb/hr) or 25 pounds per day, NO_X 5 pounds per hour (lb/hr) or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour (lb/hr) or 25 pounds per day, VOC 3 pounds per hour (lb/hr) or 15 pounds per day:

(1) One (1) No. 2 fuel oil fired poultry incinerator, installed in 2007, with an afterburner and a 70 lb/hr waste capacity, located at the animal sciences farm, 5675 W 600 N, West Lafayette, Indiana; [326 IAC 4-2-1]

(2) One (1) No. 2 fuel oil fired animal carcass incinerator for swine, installed in 1991 or 1992, with an afterburner and a 100 lb/hr waste capacity, located at the animal sciences farm, 5675 W 600 N, West Lafayette, Indiana; [326 IAC 4-2-1]

(3) One (1) natural gas fired incinerator identified as RAD1, installed in 1986, with primary and secondary chambers and a 50 lb/hr waste capacity, for burning laboratory waste and non-infectious biological material contaminated with low level radioactivity, located at the By-Product Material Storage Building North (BMSN). [326 IAC 4-2-1]

(4) One (1) natural gas fired incinerator identified as RAD2, installed in 1996, with an afterburner and a 50 lb/hr waste capacity, for burning laboratory waste and non-infectious biological material contaminated with low level radioactivity, located at the By-Product Material Storage Building North (BMSN). [326 IAC 4-2-1]

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

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

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

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

SECTION B GENERAL CONDITIONS

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

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

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

(a) The Part 70 Operating Permit Renewal, T 157-27313-00012, is issued for a fixed term of five (5) years 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 Clan 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 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.6 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.7 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.8 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

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

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

B.9 Certification [326 IAC 2-7-4(f)] [326 IAC 2-7-6(1)] [326 IAC 2-7-5(3)(C)]

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

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

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

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

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

B.10 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;

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

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

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

B.11 Preventive Maintenance Plan [326 IAC 2-7-5(13)] [326 IAC 1-6-3]

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

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

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

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

The Permittee shall implement the PMPs.

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

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

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

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

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

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.12 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, no later than four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

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

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

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

no later than two (2) working days of the time when emission limitations were exceeded due to the emergency.

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

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

B.13 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.14 Prior Permits Superseded [326 IAC 2-1.1-9.5] [326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T157-27313-00012 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.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)] [326 IAC 2-7-8(a)] [326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.16 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] [326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ, and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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 the deadline specified pursuant to 326 IAC 2-7-4(a)(2)(D) in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.17 Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12] [40 CFR 72]

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

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

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

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

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

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b), (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 limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

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

and

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

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

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

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1), (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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

(d) Alternative Operating Scenarios Part 70 Operating Permit
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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 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 (lb/hr) and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour (lb/hr).

C.2 Opacity [326 IAC 5-1]

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

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

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

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

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

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

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

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

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

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

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

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

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.8 Performance Testing [326 IAC 3-6]

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

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

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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 a certification that meets the requirements of 326 IAC 2-7-6(1) 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.9 Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

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 or of initial start-up, whichever is later, 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 or the date of initial startup, whichever is later, 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(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.

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

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

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

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

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

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

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

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

C.13 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

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

C.14 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

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

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

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

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

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

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit no later than 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:

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

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

The statement must be submitted to:

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

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

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

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

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

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

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported, except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by a "responsible official" as defined by 326 IAC 2-7-1(34). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

(b) The address for report submittal is:

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

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

(d) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period. Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

(e) 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 Electric Utility Steam Generating Unit, then for that project the Permittee shall:

(1) Submit to IDEM, OAQ a copy of the information required by (c)(1) in Section C – General Record Keeping Requirements

(2) Submit a report to IDEM, OAQ within sixty (60) days after the end of each year during which records are generated in accordance with (d)(1) and (2) in Section C – General Record Keeping Requirements. The report shall contain all information and data describing the annual emissions for the emissions units during the calendar year that preceded the submission of 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

(f) The report for a project at an existing emissions unit other than Electric Utility Steam Generating 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 wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction project.

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

(g) 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.19 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

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

(a) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2013, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 75 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

After the startup of Boiler 7 this boiler, identified as Boiler 1 shall be decommissioned within one hundred and eighty (180) days:

(a1) One (1) spreader stoker coal fired boiler, identified as Boiler 1, with installation completed in 1960, with a nominal capacity of 281 MMBtu/hr, with a multi-cyclone collector and an electrostatic precipitator for particulate matter control, exhausting to stack WADE 01. Boiler 1 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After the fuel change from coal to natural gas in Boiler 2, the coal usage shall be discontinued in this boiler, identified as Boiler 2:

(b1) One (1) spreader stoker coal fired boiler, identified as Boiler 2, with installation completed in 1967, with a nominal capacity of 274 MMBtu/hr, with a multi-cyclone collector and a multi-compartment baghouse for particulate matter control, exhausting to stack WADE 02. Boiler 2 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After fuel Change to Natural Gas:

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in 2013, with a maximum heat input capacity of 315 MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

(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.1.1 Nitrogen Oxides Emission Limitation [326 IAC 2-2-4]

In order to make the requirements of 326 IAC 2-2 (PSD Requirements) not applicable to the addition of natural gas fired burners to the existing Boilers 1 and 2, the following limits shall apply:

(a) The combined natural gas usage for Boiler 1 and Boiler 2 shall not exceed 395 million cubic feet (MMCF) per twelve (12) consecutive month period. Compliance with this limit shall be determined at the end of each month.

(b) NO_X emissions from the Boiler 1 and Boiler 2 natural gas fired burners shall not exceed 200 pounds per million cubic feet (lb/MMCF) of natural gas.

Note: These limits shall cease for Boiler 1 after Boiler 1 is decommissioned. These Limits shall cease for Boiler 2 after Boiler 2 is converted to Natural Gas."

D.1.1.1 Prevention of Significant deterioration (PSD) Minor Limit [326 IAC 2-2]

(a) The CO emissions from the Boiler identified as Boiler 2 shall be limited as follows:

(1) The natural gas usage of the boiler, identified as Boiler 2 shall be less than 2,791 million cubic feet per twelve (12) consecutive month period, with compliance determined at the end of each month.

(2) The CO emissions shall not exceed 51 pounds per million cubic feet of natural gas.

Compliance with these limits, with the net contemporaneous increases from the new emission units and the net contemporaneous decreases from the Boiler 1 (2009 Modification) will ensure that the CO emissions from the Boiler, identified as Boiler 2 is less than 100 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2009/2012 modification.

(b) The combined NOx emissions from the natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 and the duct burner shall not exceed 14.1 pounds per hour on a 30-day rolling basis. Compliance with this limit, with the net contemporaneous increases from the new emission units and the net contemporaneous decreases from the Boiler 1 (2009 Modification) will ensure that the NOx emissions from the natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 and the duct burner in combination with other contemporaneous increases and decreases is less than 40 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2009/2012 modification.

D.1.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

(a) Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating), particulate matter (PM) emissions from Boiler 1 and Boiler 2 shall not exceed 0.64 pound per million British thermal units (lb/MMBtu) of heat input.

(b) Condition D.1.2 - Particulate Emission Limitations for Sources of Indirect Heating, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.2 – Particulate Emission Limits for Sources of Indirect Heating, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas."

D.1.2.1 Particulate Emission Limitations for Sources of Indrirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the boiler, identified as Boiler 2 and the natural gas-fired combustion turbine/heat recovery steam generator, identified as CT/HRSG1 shall not exceed 0.168 pounds per million Btu heat input (lb/MMBtu), each.

Note: The PM emissions limit for Boiler 2 shall become effective after Boiler 2 is converted to natural gas."

D.1.3 SO_2 PSD Emission Limit [326 IAC 2-2-4]

(a) Pursuant to Construction Permit PC (79) 1680, issued June 6, 1988, 326 IAC 2-2 (Prevention of Significant Deterioration), and 326 IAC 7-1.1-2, the following conditions became effective upon start-up of Boiler 5:

(1) Sulfur dioxide emissions from Boiler 1 and Boiler 2 shall be limited to 5.43 pounds per million British thermal units (lb/MMBtu) of heat input and to a total of 26.5 tons from Boiler 1 and Boiler 2 on any calendar day.

(2) The 24-hour emission limit for sulfur dioxide shall be calculated by using the sulfur content of the coal as presently reported to the OAQ in accordance with 326 IAC 3-7-2 or 3-7-3. The daily coal usage will be calculated by the use of steam production data and an evaporation factor (pounds of steam per pounds of coal). The evaporation factor shall be 8.4 pounds of steam per pound of coal. Purdue University may request a permit modification to adjust this factor if performance data warrants a review.

(b) When the daily coal usage is 420 tons or less for Boiler 1 and Boiler 2, a daily sulfur dioxide emissions level need not be provided.

(c) The stack height on the existing boilers may be increased to 65 meters without obtaining approval from the IDEM, OAQ.

(d) The Permittee may at any time submit further modeling data in an effort to demonstrate that a higher 24-hour sulfur dioxide emission level from Boiler 1 and Boiler 2 will protect the sulfur dioxide air quality standards using procedures acceptable to the OAQ. The OAQ, after appropriate review, may adjust the 24-hour sulfur dioxide limit if the air quality analysis supports an adjusted level.

(e) Condition D.1.3 – SO_2 PSD Emission Limit, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.3 – SO_2 PSD Emission Limit, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas."

D.1.4 Sulfur Dioxide Emission Limitations (SO_2) [326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from Boiler 1 and Boiler 2 shall not exceed six and zero-tenths (6.0) pound per million British thermal units (lb/MMBtu), using a calendar month average.

(b) Condition D.1.4 – Sulfur Dioxide Emission Limitations (SO_2), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.4 – Sulfur Dioxide Emission Limitations (SO_2), shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.5 Retirement of Existing Operations [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2, the Permittee shall permanently discontinue the operation of Boiler 1 within one hundred eighty (180) days of the startup date for Boiler 7. NO_X emissions from Boiler 7 shall not exceed 40 tons during this period.

(b) Within thirty (30) days after the date Boiler 1 is decommissioned, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 1 was decommissioned.

D.1.5.1 Retirement of Existing Operations [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2, after the conversion of Boiler 2 to natural gas, the Permittee shall immediately discontinue the use of coal in the spreader stoker coal fired boiler.

(b) Within thirty (30) days after the date Boiler 2 is converted to natural gas, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 2 was converted to use natural gas.

D.1.6 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, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limitation established by 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)]
Operation of the emission control devices is not required during these times unless necessary to comply with these limits.

(2) 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 and stated in Section C - Opacity. 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 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.

(c) Condition D.1.6 – Temporary Alternative Opacity Limitations, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.6 – Temporary Alternative Opacity Limitations, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.7 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for Boiler 1 and Boiler 2 and their emission control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.1.8 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) Compliance with the PM limitation for Boiler 1 and Boiler 2 shall be determined by performance stack tests conducted using methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following 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 obligations with regard to the performance testing required by this condition.

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

(b) In order to demonstrate compliance with Condition D.1.1.1(a) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after Boiler 2 is converted to natural gas, the Permittee shall conduct CO emissions stack testing of the emissions from stack WADE 2 utilizing methods as approved by the commissioner. This testing shall be done once to demonstrate compliance with the CO limit. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(c) Condition D.1.8(a) – Testing Requirements, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.8(a) – Testing Requirements, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.”

D.1.9 Particulate Control [326 IAC 2-7-6(6)]

(a) Except as otherwise provided by statute or rule or in this permit, the multiclone and electrostatic precipitator (ESP) for Boiler 1 shall be in operation and control emissions at all times that the boiler, vented to that multiclone and ESP, is in operation.

(b) Except as otherwise provided by statute or rule or in this permit, the multiclone and baghouse for particulate control for Boiler 2 shall be in operation and control emissions at all times that the boiler, vented to that multiclone and baghouse, is in operation.

(c) Condition D.1.9 shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.9 shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.10 Continuous Emissions Monitoring [326 IAC 3-5] [40 CFR 64]

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A) (Continuous Monitoring of Emissions), continuous emission monitoring systems (CEMS) for Boiler 1 and Boiler 2 shall be calibrated, maintained, and operated for measuring opacity, which meet all applicable performance specifications of 326 IAC 3-5-2 and 40 CFR 64. For Boiler 1 and Boiler 2, the COMS shall be in operation in accordance with 326 IAC 3-5 and 40 CFR Part 60 when fuel is being combusted in the associated boiler.

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

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

(d) The requirement to perform continuous opacity monitoring is not applicable to Boiler 1 once it shut down and is not applicable to Boiler 2 after it is converted to natural gas.

D.1.10.1 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx 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 CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

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

D.1.11 Continuous Opacity Monitoring [326 IAC 3-5] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(a) 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 more than twenty-four (24) hours after the start of the malfunction or down time.

(b) 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.

(c) Method 9 readings may be discontinued once a COMS is online.

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

(e) Condition D.1.11 – Continuous Opacity Monitoring, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.11 – Continuous Opacity Monitoring, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.12 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2-1]

(a) Pursuant to 326 IAC 7-2-1(c), 326 IAC 3-7, and Construction Permit PC (79) 1680, the Permittee shall demonstrate that the sulfur dioxide emissions from Boiler 1 and Boiler 2 do not exceed the emission limitations specified in Conditions D.1.3 and D.1.4.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, the coal sampling and analysis data shall be as follows:

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) Pursuant to 326 IAC 3-7-2(b)(2) and 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

(3) The Permittee shall meet the minimum sampling requirements specified in 326 IAC 3-7-2(b)(3), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e).

(4) 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.

(c) 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 instead of the fuel sampling and analysis required in (b). [326 IAC 7-2-1(g)]

(d) Condition D.1.12 - Sulfur Dioxide Emissions and Sulfur Content, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.12 – Sulfur Dioxide Emissions and Sulfur Content, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

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

D.1.13 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) For Boiler 1:

(1) In the event of emissions exceeding twenty-five percent (25%) average opacity for three (3) consecutive six (6)-minute averaging periods, appropriate response steps shall be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty-five percent (25%). 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. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(2) Opacity readings in excess of twenty-five percent (25%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(b) For Boiler 2:

(1) In the event of emissions exceeding twenty percent (20)% average opacity for three (3) consecutive six (6)-minute averaging periods, appropriate response steps shall be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced, and adjustment of flue gas conditioning rate, and the baghouse being returned to service. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(2) Opacity readings in excess of twenty percent (20%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(c) Periods of elevated opacity that are subject to a Temporary Alternative Opacity Limitation (TAOL) when building a new fire in a boiler, shutting down a boiler, removing ashes from the fuel bed or furnace in a boiler, or blowing tubes, need not be included in the averaging periods for (a) and (b) of this condition.

(d) Condition D.1.13 – Opacity Readings, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.13 – Opacity Readings, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.14 Electrostatic Precipitator Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS:

(a) The ability of the ESP to control particulate emissions from Boiler 1 shall be monitored once per day, when the unit is in operation, by measuring and recording the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets.

(b) When for any one reading, operation is outside one of the normal ranges shown below, or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A voltage or current reading outside the normal range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Boiler 1:

(1)	Primary voltage:	275 - 430 V
(2)	Secondary voltage:	29 - 45 kV
(3)	T-R set secondary current:	150 - 405 mA

(c) Condition D.1.14 – Electrostatic Precipitator Parametric Monitoring, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned.

D.1.15 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS:

(a) The Permittee shall record the pressure drop across the baghouse used in conjunction with Boiler 2, at least once per day when the process is in operation when venting to the atmosphere. When for any one reading, the pressure drop across the baghouse is outside the normal range of 1.0 and 7.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(b) The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, and shall be calibrated or replaced in accordance with the manufacturer's specifications. The specifications shall be available on site with the Preventive Maintenance Plan.

(c) Condition D.1.15 – Baghouse Parametric Monitoring, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.16 Broken or Failed Bag Detection – Multi-Compartment Baghouse [40 CFR 64]

(a) 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.

(b) Condition D.1.16 – Broken or Failed Bag Detection, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.17 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)] [326 IAC 3-7-2] [326 IAC 3-7-3]

(a) Whenever coal sampling is not being performed and the SO_2 continuous emission monitoring system (CEMS) is being utilized to demonstrate compliance with the 24-hour emission limit for SO_2 in Condition D. 1.3(a):

If the SO_2 continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustments, for twenty-four (24) hours or more, fuel sampling shall be conducted 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.

(b) Condition D.1.17 – SO2 Monitoring System Downtime, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.17 – SO2 Monitoring System Downtime, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

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

D.1.18 Record Keeping Requirements

(a) To document the compliance status with Condition D. 1.1, the Permittee shall maintain records including the following:
   (1) Monthly records of total natural gas usage for Boiler 1 and Boiler 2.
   (2) Documentation of NO_X emission rate for the Boiler 1 and Boiler 2 gas burners.

   Note: Condition D.1.18(a) shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(b) To document the compliance status with Section C - Opacity and the particulate matter and opacity Conditions D. 1.2, D. 1.6, D. 1.8, D. 1.9, D. 1.11, D. 1.13, D. 1.14, and D. 1.15, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits in Section C - Opacity and Condition D. 1.6.

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

   (2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6.

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

   Note: Condition D.1.18(b), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(c) To document the compliance status with Condition D. 1.14, the Permittee shall maintain daily records of the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets for the ESP for Boiler 1 whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of a reading (e.g. the process did not operate that day).

Note: Condition D.1.18(c), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned.

(d) To document the compliance status with Condition D. 1.15, the Permittee shall maintain daily records of the pressure drop across the baghouse for Boiler 2 whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of a reading (e.g. the process did not operate that day).

Note: Condition D.1.18(d), shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

(e) To document the compliance status with SO_2 Conditions D. 1.3, D. 1.4, D. 1.12, and D. 1.17, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limits as required in Conditions D. 1.3 and D. 1.4.

(1) All fuel sampling and analysis data, pursuant to 326 IAC 7-2 or all SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g), and 40 CFR 60.45.

(2) Daily fuel usage for each of Boiler 1 and Boiler 2.

Note: Condition D.1.18(e), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(f) To document the compliance status with Conditions D.1.10.1 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain the monthly records of the NOx emissions from the combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 based on CEM data.

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

D.1.19 Reporting Requirements

(a) A quarterly report of opacity exceedances shall be submitted 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).

Note: Condition D.1.19(a), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(b) A quarterly report of the calendar month average coal sulfur content, coal heat content, and sulfur dioxide emission rate in pounds per million British thermal units (lb/MMBtu) and the total monthly coal consumption shall be submitted not later than thirty (30) days following the end of each calendar quarter. [326 IAC 7-2-1(c)(2]
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).

Note: Condition D.1.19(b), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(c) A quarterly report of the information to document the compliance status with Condition D.1.1(a) and D.1.1.1(a) 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.

(d) Whenever coal sampling is not being performed and the SO_2 continuous emission monitoring system (CEMS) is being utilized to demonstrate compliance with the 24-hour emission limit for SO_2 in Condition D.1.3(a):

Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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

Note: Condition D.1.19(d), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(d) One (1) circulating fluidized bed coal fired boiler, identified as Boiler 5, with installation completed in 1991, with a nominal capacity of 279 MMBtu/hr, with a baghouse for particulate matter control and limestone injection for sulfur dioxide control, combusting natural gas for ignition, exhausting to stack WADE 05. Boiler 5 has continuous emissions monitoring systems (CEMS) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM).

Under the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Db), Boiler 5 is considered an affected source.

(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.2.1 Boiler 5 PSD Emission Limits [326 IAC 2-2-3] [326 IAC 6-2-1(g)]

Pursuant to Construction Permit PC (79) 1680, issued June 6, 1988, and 326 IAC 2-2 (Prevention of Significant Deterioration), the following requirements apply to Boiler 5:

(a) Sulfur dioxide emissions from Boiler 5 shall not exceed:

(1) 0.9 pounds per million British thermal units (lb/MMBtu) of heat input based on a 30-day rolling weighted average basis, and

(2) 1.1 pounds per million British thermal units (lb/MMBtu) of heat input based on a block 24-hour average basis.

(b) Particulate matter emissions from Boiler 5 shall not exceed 0.05 pounds per million Btu of heat input.

(c) Carbon monoxide emissions from Boiler 5 shall not exceed 0.27 pounds per million British thermal units (lb/MMBtu) of heat input.

(d) The rate of heat input into the boiler shall not exceed 279 million Btu's per hour.

D.2.2 Sulfur Dioxide Emission Limitations [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from Boiler 5 shall not exceed six and zero-tenths (6.0) pound per million Btu (lb/MMBtu), using a calendar month average.

D.2.3 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limitation established by 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)]

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed forty percent (40%); however, opacity shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of forty percent (40%) shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60)-minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period.

(c) If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(a), 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.2.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for Boiler 5 and its emission control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.2.5 Testing Requirements [326 IAC 2-7-6(1), (6)] [326 IAC 2-1.1-11]

(a) Compliance with the Boiler 5 PM limitation in Condition D.2.1(b) shall be determined by performance stack tests conducted using methods as approved by the Commissioner.

(b) Compliance with the Boiler 5 CO limitation in Condition D.2.1(c) shall be determined by performance stack tests conducted using methods as approved by the Commissioner.

(c) This testing shall be repeated by December 31 of every second calendar year following 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 obligations with regard to the performance testing required by this condition.

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

D.2.6 Compliance Determination Requirements [326 IAC 2-2]

(a) Except as otherwise provided by statute, rule, or this permit, a circulating fluidized bed boiler with alkali injection shall be used as needed to maintain compliance with the sulfur dioxide emission limitations in Conditions D.2.1 and D.2.2 for Boiler 5.

(b) Compliance with the sulfur dioxide emission limits in Conditions D.2.1(a) and D.2.2 for Boiler 5 shall be determined on a 30-day rolling weighted average emission basis.

(c) Compliance with the block 24-hour average sulfur dioxide emission limitation in Condition D.2.1(a)(2) for Boiler 5 shall be determined by using the continuous sulfur dioxide emission monitoring data.

D.2.7 Continuous Emissions Monitoring [326 IAC 3-5] [40 CFR 64]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), opacity, SO_2, and NO_X continuous emission monitoring systems (CEMS) for Boiler 5 shall be calibrated, maintained, and operated for measuring opacity, SO_2, and NO_X which meet the performance specifications of 326 IAC 3-5-2 and 40 CFR 60. For Boiler 5, the Continuous Opacity Monitoring System (COMS) shall be in operation in accordance with 326 IAC 3-5 and 40 CFR Part 60 when fuel is being combusted in the boiler.

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

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

D.2.8 Continuous Opacity Monitoring [326 IAC 3-5] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(a) 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 more than twenty-four (24) hours after the start of the malfunction or down time.

(b) 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.

(c) Method 9 readings may be discontinued once a COMS is online.

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

D.2.9 Particulate Control [326 IAC 2-7-6(6)] [40 CFR 64]

(a) Except as otherwise provided by statute or rule or in this permit, the baghouse shall be operated at all times that Boiler 5 is in operation and coal is being combusted in the boiler.

(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.2.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2-1]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Boiler 5 do not exceed the equivalent of 6.0 pound per million British thermal units (lb/MMBtu) of heat input, using a calendar month average.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data shall be collected as follows:

    (1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) Pursuant to 326 IAC 3-7-2(b)(2) and 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

(3) The Permittee shall meet the minimum sampling requirements specified in 326 IAC 3-7-2(b)(3), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e).

(4) 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.

(c) 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 instead of the fuel sampling and analysis required in (b). [326 IAC 7-2-1(g)]

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

D.2.11 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(1) In the event of emissions exceeding twenty percent (20%) average opacity for three (3) consecutive six (6)-minute averaging periods, appropriate response steps shall be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced, adjustment of flue gas conditioning rate, and the baghouse being returned to service. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(2) Opacity readings in excess of twenty percent (20%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

D.2.12 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS:

(a) The Permittee shall record the pressure drop across the baghouse used in conjunction with Boiler 5, at least once per day when the process is in operation when venting to the atmosphere. When for any one reading, the pressure drop across the baghouse is outside the normal range of 1.0 and 7.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(b) A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, and shall be calibrated or replaced in accordance with the manufacturer's specifications. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

D.2.13 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)] [326 IAC 3-7-2] [326 IAC 3-7-3]

Whenever the SO_2 continuous emission monitoring system for Boiler 5 is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the Permittee shall:

(a) Monitor and record boiler load, fuel sulfur content, and limestone injection rate, to demonstrate that the operation of the limestone injection system continues in a manner typical for the boiler load and sulfur content of the coal fired. Limestone injection parametric monitoring readings shall be recorded at least once per hour until the primary CEMS or a backup CEMS is brought online.

(b) 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.

D.2.14 NO_X Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)] [326 IAC 3-7-2] [326 IAC 3-7-3]

Whenever the NO_X continuous emission monitoring system for Boiler 5 is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the Permittee shall operate Boiler 5 in a manner consistent with best combustion practices.

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

D.2.15 Record Keeping Requirements

(a) To document the compliance status with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the opacity requirements in Conditions D.2.5, D.2.10, D.2.11, and D.2.14, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the opacity limits in Conditions D.2.5 and D.2.14.

(1) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6.

(2) The results of all Method 9 visible emission readings taken during any periods of COM downtime.

(b) To document the compliance status with the SO_2 requirements in Conditions D.2.1, D.2.4, D.2.8, D.2.10, D.2.13, and D.2.16, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the applicable SO_2 limits in Conditions D.2.1 and D.2.4. The Permittee shall maintain records in accordance with (3) and (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 startup periods and shutdown periods for Boiler 5.

(3) All boiler load, fuel sampling and analysis, and limestone injection rate data collected for SO_2 CEMS downtime, in accordance with Conditions D.2.8 and D.2.16.

(4) Actual fuel usage during each SO_2 CEM system downtime.

(c) To document the compliance status with the NO_X requirements in Condition D.2.10, the Permittee shall maintain records of all NO_X and CO_2 or O_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6.

(d) To document the compliance status with the CO requirements in Conditions D.2.1(b) and D.2.7(a), the Permittee shall maintain data and results from the most recent stack test for Boiler 5. Records shall be complete and sufficient to establish compliance with the CO limit in Condition D.2.1(b).

(e) To document the compliance status with Condition D.2.12, the Permittee shall maintain daily records of the pressure drop across the baghouse for Boiler 5 whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of a reading (e.g. the process did not operate that day).

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

D.2.16 Reporting Requirements

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document the compliance status with Conditions D.2.1(a), D.2.4, and D.2.5, shall be submitted 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).

(b) Pursuant to Condition D.2.8(c) regarding the block 24 hour average SO_2 emission limitation for Boiler 5, the quarterly report for SO_2 shall explain whether any excess 24 hour average emission rates due to startup and shutdown were excluded from the compliance determination.

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

(1) date of downtime;

(2) time of commencement;

(3) duration of each downtime;

(4) reasons for each downtime; and

(5) nature of system repairs and adjustments.

(d) Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

The reports submitted by the Permittee 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 D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(c) One (1) natural gas and distillate fuel oil fired boiler, identified as Boiler 3, with installation started in 1973 or 1974 and completed in 1974, with a nominal capacity of 286 MMBtu/hr, exhausting to stack WADE 03. Boiler 3 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Under the Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 NSPS (40 CFR 60, Subpart D), Boiler 3 is considered an affected source.

(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.3.1 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limitation established by 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)]

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed forty percent (40%); however, opacity shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of forty percent (40%) shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60)-minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period.

(c) If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(a), 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.3.2 Sulfur Dioxide (SO_2) [326 IAC 7-1.1]

Pursuant to 326 IAC 7-1.1-2(a)(3), sulfur dioxide emissions from Boiler 3 shall not exceed five-tenths (0.5) pound per million Btu (lb/MMBtu), using a calendar month average, when combusting only distillate oil or a combination of only distillate oil and natural gas.

D.3.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for Boiler 3 and any emission control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.3.4 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems for Boiler 3 shall be calibrated, maintained, and operated for measuring NO_X, 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) If the Administrator approves alternative monitoring requirements in lieu of the COM requirements for Boiler 3, then IDEM, OAQ, may require additional PM stack testing and Method 9 opacity readings to demonstrate compliance with 326 IAC 5-1 and 326 IAC 6-2, pursuant to 326 IAC 3-5-1(c)(2)(A)(ii).

(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, 40 CFR 60, or 40 CFR 75.

D.3.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the limits specified in Condition D.3.2, using a calendar month average.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7-4, fuel sampling and analysis data shall be collected as follows:

(1) The Permittee may rely upon vendor analysis of fuel delivered, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; or,

(2) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with 326 IAC 3-7-4(a).

(A) Oil samples shall be collected from the tanker truck load 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.

(c) 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)]

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

D.3.6 Record Keeping Requirements

(a) To document the compliance status with the opacity requirements in Condition D.3.1, the Permittee shall maintain records in accordance with (1) and (2) below. Records and shall be complete and sufficient to establish compliance with the opacity limits in Condition D.3.1.

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

(2) The opacity exceedances from COMS data or results of all daily Method 9 visible emission (VE) readings.

(b) To document the compliance status with the SO_2 requirements in Conditions D.3.2 and D.3.5, the Permittee shall maintain records in accordance with (1) and (2) below. Records and shall be complete and sufficient to establish compliance with the SO_2 limits in Condition D.3.2.

(1) All fuel sampling and analysis data, pursuant to 326 IAC 7-2.

(2) Actual fuel usage since last compliance determination period.

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

D.3.7 Reporting Requirements

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:

(a) date of downtime;

(b) time of commencement;

(c) duration of each downtime;

(d) reasons for each downtime; and

(e) nature of system repairs and adjustments.

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.4 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(f) One (1) natural gas fired boiler, identified as Boiler 7, permitted in 2010, with a nominal capacity of 290 MMBtu/hr, exhausting to stack WADE 03. Boiler 7 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) for compliance with NSPS requirements.

Under the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Db), Boiler 7 is considered an affected source.

(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.4.1 Boiler 7 PSD Minor Limits [326 IAC 2-2]

(a) The natural gas usage for Boiler 7 shall not exceed 2,491 million cubic feet (MMCF) per twelve (12) consecutive month period. Compliance with this limit shall be determined at the end of each month.

(b) NO_X emissions from Boiler 7 shall not exceed 0.049 pounds per million British thermal units (lb/MMBtu) of heat input.

(c) PM emissions from Boiler 7 shall not exceed 1.9 pounds per million standard cubic feet (MMCF) of natural gas.

(d) PM_{10} emissions from Boiler 7 shall not exceed 7.6 pounds per million standard cubic feet (MMCF) of natural gas.

(e) $PM_{2.5}$ emissions from Boiler 7 shall not exceed 7.6 pounds per million standard cubic feet (MMCF) of natural gas.

(f) SO_2 emissions from Boiler 7 shall not exceed 0.6 pounds per million standard cubic feet (MMCF) of natural gas.

Compliance with these emission limits combined with the potential to emit NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2 emissions from all other emission units associated with the modification to add Boiler 7 will limit the potential to emit from this modification to less than one hundred (100) tons per year of CO, less than forty (40) tons per year of NO_X, less than twenty-five (25) tons per year of PM, less than fifteen (15) tons per year of PM_{10}, less than ten (10) tons per year of $PM_{2.5}$, and less than forty (40) tons per year of SO_2. Therefore the requirements of 326 IAC 2-2 (PSD) are not applicable to the modification to add Boiler 7.

D.4.2 Compliance Determination Requirements [326 IAC 2-2]

In order to determine compliance status with Condition D.4.1 - PM, PM_{10}, $PM_{2.5}$ and SO2 — Boiler 7 PSD Minor Limits, the Permittee shall only use natural gas in Boiler 7 and compliance with the NOx emission limit shall be demonstrated on a 12-month rolling average.

D.4.3 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx 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 CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

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

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

D.4.4 Record Keeping Requirements

(a) To document compliance with Condition D.4.1(a), the Permittee shall maintain monthly records of natural gas usage.

(b) To document the compliance status with Condition D.4.3 - 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.

(c) In the event that a breakdown of the NOx continuous emission monitoring system (CEMS) occurs in Condition D.4.3 - 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.

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

D.4.5 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.4.1(a) shall be submitted 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.5 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(g) One (1) coal storage and handling system identified as COAL Segment 1, installed in 1960, with a nominal capacity of 110 tons/hr, including: truck unloading station with two (2) hoppers; two (2) vibratory feeders; one (1) underground belt conveyor with a magnetic separator; and one (1) bucket elevator terminating at the top of Wade Utility Plant. Coal is fed to the bunkers for Boiler 1, Boiler 2, and to the pre-crusher ahead of the indoor storage silo for Boiler 5. Emissions from the Boiler 1 and Boiler 2 bunkers are controlled by a RotoClone for each of the two (2) bunkers. The bunker for Boiler 1 exhausts to stack CB1. The bunker for Boiler 2 exhausts to CB2. COAL Segment 1 has been retained as a backup system for COAL Segment 2.

(h) One (1) coal storage and handling system identified as COAL Segment 2, installed in 1996, with a nominal capacity of 107 tons/hr, including: truck unloading and two (2) in-ground hoppers, two (2) vibratory feeders; one (1) totally enclosed tubular conveyor identified as BC-1 equipped with a magnetic separator and with emissions controlled by a baghouse exhausting to stack CV1; one (1) transfer enclosure with one (1) coal sampler, with emissions controlled by a baghouse exhausting to stack CV2; and one (1) totally enclosed tubular conveyor identified as BC-2 terminating at the top of Wade Utility Plant, with emissions from the final transfer point controlled by a baghouse exhausting to stack CV3. Coal is fed to the bunkers for Boiler 1, Boiler 2, and to the pre-crusher ahead of the indoor storage silo for Boiler 5. Emissions from the Boiler 1 and Boiler 2 bunkers are controlled by a RotoClone for each of the two (2) bunkers. The bunker for Boiler 1 exhausts to stack CB1. The bunker for Boiler 2 exhausts to CB2.

(i) One (1) outdoor coal storage pile area identified as COAL PILE 1, permitted in 1960 and 1996, with particulate matter emissions exhausting to the atmosphere.

(j) One (1) coal preparation system for Boiler 5, with installation completed in 1991, with a nominal capacity of 12.68 tons/hr, including: one (1) enclosed 125 ton/hr Redler conveyor with one (1) enclosed pre-crusher (both serving in a back-up capacity), one (1) 150 ton/hr enclosed belt conveyor and pre-crusher with installation completed in 2009. Both lines feed into; one (1) coal storage bunker, two (2) weigh belt feeders; and two (2) enclosed crushers with emission directed to a baghouse exhausting to stack CB5.

Under the Standards of Performance for Coal Preparation Plants NSPS (40 CFR 60, Subpart Y), the coal preparation system for Boiler 5 including the crushers and COAL Segment 2 are considered affected sources.

Insignificant Activities:
Coal bunker and coal scale exhausts and associated dust collector vents.

(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.5.1 PSD Minor Limit [326 IAC 2-2-1]

The emissions from the coal storage and handling equipment included in COAL Segment 2 shall be limited as follows:

(1) Particulate matter (PM) emissions from CV1 shall not exceed 1.71 pounds per hour.

(2) PM_{10} emissions from CV1 shall not exceed 1.02 pounds per hour.

(3) Particulate matter (PM) emissions from CV2 shall not exceed 2.28 pounds per hour.

(4) PM_{10} emissions from CV2 shall not exceed 1.36 pounds per hour.

(5) Particulate matter (PM) emissions from CV3 shall not exceed 1.71 pounds per hour.

(6) PM_{10} emissions from CV3 shall not exceed 1.02 pounds per hour.

Compliance with the above limits shall limit PM and PM_{10} emissions less than 25 and 15 tons per year respectively, and will render the requirements of 326 IAC 2-2-1(x) and 326 IAC 2-2-1(jj) (PSD Requirements) not applicable to the coal preparation system for Boiler 5.

D.5.2 Particulate [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the COAL Segment 1 shall not exceed 52.23 pounds per hour (lb/hr) when operating at a process weight rate of 110 tons per hour (ton/hr), and the allowable particulate emission rate from the COAL Segment 2 shall not exceed 51.96 pounds per hour (lb/hr) when operating at a process weight rate of 107 tons per hour (ton/hr). Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour (lb/hr) shall be accomplished by use of the equation:

$E = 55.0\ P^{0.11} - 40$ where E = rate of emission in pounds per hour (lb/hr); and
P = process weight rate in tons per hour (ton/hr).

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the Boiler 5 coal preparation system shall not exceed 22.48 pounds per hour (lb/hr) when operating at a process weight rate of 12.68 tons per hour (ton/hr). Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour (lb/hr) shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$ where E = rate of emission in pounds per hour (lb/hr); and
P = process weight rate in tons per hour (ton/hr).

D.5.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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

Compliance Determination Requirements

D.5.4 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, in order to comply with Conditions D.5.1 and D.5.2, the RotoClones, cartridge filters, and baghouses for particulate control shall be in operation and control emissions at all times the associated coal processing or conveying is in operation.

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

D.5.5 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the coal unloading station shall be performed once per week during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of each coal transfer exhaust point shall be performed once per week during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.

(c) 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.

(d) 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.

(e) 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.

(f) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

D.5.6 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) The Permittee shall record the pressure drop across each of the baghouses used in conjunction with the coal transfer drop points at least once per week when coal is being transferred. When for any one reading, the pressure drop across baghouse CV1 or CV3 is outside the normal range of 4.0 and 10.0 inches of water or a range established during the latest stack test, or the pressure drop across baghouse CV2 is outside the normal range of 5.0 to 12.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(b) The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, and shall be calibrated or replaced in accordance with the manufacturer's specifications. The specifications shall be available on site with the Preventive Maintenance Plan.

D.5.7 Broken or Failed Bag Detection - Single and Multi-Compartment Baghouses [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(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. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

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

(c) 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.

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

D.5.8 RotoClone Failure Detection [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

In the event that RotoClone failure has been observed:

The failed units and the associated process will be shut down immediately until the failed units have been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions). Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

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

D.5.9 Record Keeping Requirements

(a) To document the compliance status with Condition D.5.5, the Permittee shall maintain records of the weekly visible emission notations of the coal unloading and coal transfer exhaust points. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g., the process did not operate that week).

(b) To document the compliance status with Condition D.5.6, the Permittee shall maintain weekly records of the total static pressure drop across each baghouse. The Permittee shall include in its weekly 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 week).

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

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(k) One (1) pneumatic ash handling system for fly ash and bottom ash from Boiler 1 and Boiler 2, identified as ASH Segment 1, with a nominal capacity of 14 tons per hour (ton/hr), installed in approximately 1960 and modified in 2002. Ash/particulate matter collected from the primary, secondary and tertiary (baghouse) collection units are transferred to the existing ash silo. Ash accumulated in this silo is removed via a water mixer into trucks. Particulate matter that passes through the tertiary (baghouse) filter is exhausted to stack ASH1 while air from the ash silo is directed to a final filter before exhausting to stack AB1. Ash/particulate matter is transported through the system by an electric vacuum pump.

(l) One (1) pneumatic ash handling system for fly ash and bottom ash from Boiler 5, identified as ASH Segment 2, installed in 1991 and modified in 2002, exhausting to stacks ASH5A and ASH5B, with a nominal capacity of 20 tons/hr, with dust from ash transfer to the storage silo controlled by primary and secondary separator with tertiary baghouse filter, ASH5D. Ash is transferred from the silo to trucks at a nominal capacity of 300 tons/hr; dust is controlled by water mix, or by use of a telescoping spout with air displaced from the truck directed through a “filter module” with five canister filters which exhaust to the atmosphere though a vent, ASH5C.

(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.6.1 PSD Minor Limits for Ash Segment 2 [326 IAC 2-2-1]

Emissions from the Ash Segment 1 associated with Boiler 1 and Boiler 2 shall be limited as follows:

(1) Particulate matter (PM) emissions from ASH1 shall not exceed 2.85 pounds per hour.

(2) PM_{10} emissions from ASH1 shall not exceed 1.70 pounds per hour.

(3) Particulate matter (PM) emissions from AB1 shall not exceed 2.85 pounds per hour.

(4) PM_{10} emissions from AB1 shall not exceed 1.70 pounds per hour.

Compliance with the above limits shall limit PM and PM_{10} emissions less than 25 and 15 tons per year respectively, and will render the requirements of 326 IAC 2-2-1(x) and 326 IAC 2-2-1(jj) (PSD Requirements) not applicable to Ash Segment 1 associated with Boiler 1 and Boiler 2.

D.6.2 Particulate [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from each transfer point for the ash handling system identified as ASH Segment 1 shall not exceed 24.03 pounds per hour (lb/hr) when operating at a process weight rate of 14 tons per hour (ton/hr).

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from each transfer point for the pneumatic ash handling system identified as ASH Segment 2 shall not exceed 30.5 pounds per hour (lb/hr) when operating at a process weight rate of 20 tons per hour (ton/hr).

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

$E = 4.10 P^{0.67}$ where E = rate of emission in pounds per hour (lb/hr); and
P = process weight rate in tons per hour (ton/hr).

(c) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for the ash unloading at the maximum throughput rate of 300 tons per hour for Ash Segment 2, the concentration of particulate in the discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1,000) pounds of gases.

D.6.3 Preventative Maintenance Plan [326 IAC 2-7-5(1)(13)]

A Preventive Maintenance Plan (PMP) is required for the pneumatic ash handling systems identified as ASH Segment 1 and ASH Segment 2 and their emission control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.6.4 Particulate Control [326 IAC 2-7-10.5(d)(5)(C)]

(a) The fresh water/mixing operation for the ash truck loading system for ASH Segment 1 shall be in operation and control the particulate emissions from the ash at all times that the ash truck loading system is in operation.

(b) The baghouse of ASH1 stack and air filter for AB1 stack for particulate control, shall be in operation and control the particulate emissions from ash system at all times that the ash storage and handling system is in operation.

(c) Except as otherwise provided by statute or rule or in this permit, in order to comply with Conditions D.6.1 and D.6.2 (Particulate) related to ASH Segment 2, the baghouse filters for particulate control shall be in operation and control emissions at all times that the associated ash handling is in operation; the telescoping spout shall be in operation and control emissions at all times that the dry ash loading system is in operation; and water shall be mixed with the ash at all times to control emissions when the wet process ash loading system.

(d) The filter module and canister filters for the ASH Segment 2 dry ash loading system, for particulate control shall be in operation and control the particulate emissions at all times that the dry ash loading system is in operation.

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

D.6.5 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible Emissions Notations:

(1) Visible emission notations of the ASH1 and AB1 exhaust stacks shall be performed once per day during normal daylight operations and when the silo is receiving ash.

(2) Visible emission notations of the ash truck loading system for ASH Segment 1 shall be performed once per day during normal daylight operations when the ash trucks are receiving ash.

(3) Visible emission notations for ASH Segment 2 of the ASH5A and ASH5B exhaust stacks shall be performed once per day during normal daylight operations when transferring ash.

(4) Visible emission notations for ASH Segment 2 of the exhaust vent, ASH5C, shall be performed once per day during normal daylight operations when transferring ash through the dry ash unloader.

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. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

D.6.6 Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) The Permittee shall record the total static pressure drop across the baghouse (ASH1) and air filter (AB1) controlling emissions from the ash handling system for ASH Segment 1, at least once per day when the ash handling system is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 1.0 to 7.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps.

(b) The Permittee shall record the pressure drop across the ash silo baghouse for ASH Segment 2 at least once per week when the ash handling is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 1.0 and 7.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps.

(c) The Permittee shall record the pressure drop across the air filters controlling emissions from the ASH Segment 2 dry ash truck loading system (ASH5C), at least once per week when the dry ash truck loading system is in operation. When for any one reading, the pressure drop across the air filter is outside the normal range of 1.0 and 7.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps.

A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(d) The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, and shall be calibrated or replaced in accordance with the manufacturer's specifications. The specifications shall be available on site with the Preventive Maintenance Plan.

D.6.7 Broken or Failed Bag Detection - Single Compartment Baghouses [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(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. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

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

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

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

D.6.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.5, the Permittee shall maintain daily records of the visible emission notations of ASH1, AB-1, the ASH5A and ASH5B exhaust stacks, and the exhaust vent ASH5C. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.6.6, the Permittee shall maintain daily records of the total static pressure drop across each baghouse and air filter. 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) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(m) Material handling for the limestone injection system for Boiler 5, including pneumatic conveyance system, identified as LC5, from truck to bulk storage in a silo outside, identified as LS1, or to a "day bin", identified as LI5, inside the plant at an offload rate of approximately 12.5 tons per hour (ton/hr); gravity fed from day bin into Boiler 5. Particulate emissions are controlled by a baghouse, identified as LSBH1, on the silo and filter cartridges, identified as BVLI5, on the day bin.

Insignificant Activity:
Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983.

(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.7.1 Particulate [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from each transfer point for the limestone handling system associated with Boiler 5 shall not exceed 22.17 pounds per hour (lb/hr) when operating at a process weight rate of 12.5 tons per hour (ton/hr).

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

$E = 4.10 P^{0.67}$ where E = rate of emission in pounds per hour (lb/hr); and
P = process weight rate in tons per hour (ton/hr).

D.7.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for the limestone storage and handling operations and their emission control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.7.3 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, LSBH1, and BVLI5, for particulate control shall be in operation and control emissions at all times the associated limestone transfer points are in operation.

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

D.7.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible Emissions Notations:

(1) Visible emission notations of the limestone handling systems exhaust point, identified as LSBH1, shall be performed once per week during normal daylight operations and when the silo is receiving limestone. A trained employee shall record whether emissions are normal or abnormal.

(2) Visible emission notations of the Boiler 5 limestone day bin vent (BVLI5) shall be performed once per week during normal daylight operations when exhausting to the atmosphere. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

D.7.5 Broken or Failed Bag Detection - Single Compartment Baghouses [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(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. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

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

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

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

D.7.6 Record Keeping Requirements

(a) To document the compliance status with Condition D.7.4, the Permittee shall maintain weekly records of the visible emission notations of LSBH–1 and BVLI5. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that week).

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

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(o) One (1) natural gas fired dual chamber animal carcass incinerator, identified as ADDL, installed in 1991, with a nominal heat input capacity of 6.5 MMBtu/hr, with an 800 lb/hr waste capacity, exhausting to stack PUADDL1.

Insignificant Activities:

(1) One (1) No. 2 fuel oil fired poultry incinerator, installed in 2007, with an afterburner and a 70 lb/hr waste capacity, located at the animal sciences farm, 5675 W 600 N, West Lafayette, Indiana;

(2) One (1) No. 2 fuel oil fired animal carcass incinerator for swine, installed in 1991 or 1992, with an afterburner and a 100 lb/hr waste capacity, located at the animal sciences farm, 5675 W 600 N, West Lafayette, Indiana;

(3) One (1) natural gas fired incinerator identified as RAD1, installed in 1986, with primary and secondary chambers and a 50 lb/hr waste capacity, for burning laboratory waste and non-infectious biological material contaminated with low level radioactivity, located at the By-Product Material Storage Building North (BMSN).

(4) One (1) natural gas fired incinerator identified as RAD2, installed in 1996, with an afterburner and a 50 lb/hr waste capacity, for burning laboratory waste and non-infectious biological material contaminated with low level radioactivity, located at the By-Product Material Storage Building North (BMSN).

(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.8.1 Incinerators [326 IAC 4-2-2]

(a) Pursuant to 326 IAC 4-2-2 (Incinerators), all incinerators shall comply with the following requirements:

(1) Consist of primary and secondary chambers or the equivalent.

(2) Be equipped with a primary burner unless burning only wood products.

(3) Comply with 326 IAC 5-1 and 326 IAC 2.

(4) Be maintained, operated, and burn waste in accordance with the manufacturer's specifications or an operation and maintenance plan as specified in subsection (c).

(5) Not emit particulate matter in excess of one (1) of the following:

(A) For RAD1, with a 250 lb/hr waste capacity:

Three-tenths (0.3) pound of particulate matter per one thousand (1,000) pounds of dry exhaust gas under standard conditions corrected to fifty percent (50%) excess air.

(B) For the swine incinerator with a 100 lb/hr waste capacity, the poultry incinerator with a 70 lb/hr waste capacity, and RAD2 with a 50 lb/hr waste capacity:

Five-tenths (0.5) pound of particulate matter per one thousand (1,000) pounds of dry exhaust gas under standard conditions corrected to fifty percent (50%) excess air for incinerators with solid waste capacity less than two hundred (200) pounds per hour (lb/hr).

(6) If any of the requirements of subdivisions (1) through (5) are not met, then the owner or operator shall stop charging the incinerator until adjustments are made that address the underlying cause of the deviation.

(b) An incinerator is exempt from subsection (a)(5) if subject to a more stringent particulate matter emission limit in 40 CFR 52 Subpart P*, State Implementation Plan for Indiana.

(c) An owner or operator developing an operation and maintenance plan pursuant to subsection (a)(4) must comply with the following:

(1) The operation and maintenance plan must be designed to meet the particulate matter emission limitation specified in subsection (a)(5) and include the following:

(A) Procedures for receiving, handling, and charging waste.

(B) Procedures for incinerator startup and shutdown.

(C) Procedures for responding to a malfunction.

(D) Procedures for maintaining proper combustion air supply levels.

(E) Procedures for operating the incinerator and associated air pollution control systems.

(F) Procedures for handling ash.

(G) A list of wastes that can be burned in the incinerator.

(2) Each incinerator operator shall review the plan before initial implementation of the operation and maintenance plan and annually thereafter.

(3) The operation and maintenance plan must be readily accessible to incinerator operators.

(4) The owner or operator of the incinerator shall notify the department, in writing, thirty (30) days after the operation and maintenance plan is initially developed pursuant to this section.

(d) The owner or operator of the incinerator must make the manufacturer’s specifications or the operation and maintenance plan available to the department upon request.

D.8.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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

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

D.8.3 Record Keeping Requirements

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

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(p) One (1) no. 2 fuel oil fired Black Start electric generator, identified as BSG, with a nominal heat input capacity of 17.7 MMBtu/hr, exhausting through stack BSG-1, with a fuel limit of 113,000 gallons per year.

(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.9.1 Source Modification Limits [326 IAC 2-7-10.5(d)(5)(D)] [326 IAC 2-2-1]

(a) The input of No. 2 fuel oil to the Black Start electric generator, BSG, shall be limited to less than 113,000 gallons per 12 consecutive month period, with compliance determined at the end of each month.

(b) NO_X emissions shall not exceed 3.2 lb/MMBtu.

Compliance with these emission limits will limit the potential to emit from the modification to add Black Start Generator (BSG) to less than 25 tons per year of NO_X; therefore, the requirements of 326 IAC 2-7-10.5(f), (g), and (h) (Significant Source Modifications), 326 IAC 2-2 (Prevention of Significant Deterioration) and 326 IAC 2-1.1-4 (Federal Provisions) are not applicable to modification to add the Black Start Generator (BSG).

D.9.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for the Black Start electric generator, identified as BSG. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

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

D.9.3 Record Keeping Requirements

(a) To document the compliance status with Condition D.9.1, the Permittee shall maintain records in accordance with (1) through (5) below.

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

(2) Actual fuel oil usage since last compliance determination period and equivalent nitrogen oxides (NO_X) emissions;

(3) A certification, signed by the owner or operator, that the records of the fuel supplier certifications represent all of the fuel combusted during the period;

(4) The name of the fuel supplier; and

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

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

D.9.4 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.9.1(a) 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

Emission Unit Description:

Insignificant Activities:
Boilers using the following fuels:

(A) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour, including three (3) natural gas fired Aviation Tech Building Boilers with low-NO_X combustion systems, installed in 2000, each with 2.8 MMBtu/hr heat input capacity, identified as AV Tech Boiler 1, AV Tech Boiler 2, and AV Tech Boiler 3.

(B) Propane or liquefied petroleum gas, or butane-fired combustion sources with heat input equal to or less than six million (6,000,000) Btu per hour.

(C) Fuel oil-fired combustion sources with heat input equal to or less than two million (2,000,000) Btu per hour and firing fuel containing less than five-tenths (0.5) percent sulfur by weight.

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

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for Facilities Specified in 326 IAC 6-2-1(d)), the PM emissions from each of the boilers classified as an insignificant activity shall not exceed 0.1 pound per million British thermal units (lb/MMBtu) of heat input.

SECTION D.11 **EMISSIONS UNIT OPERATION CONDITIONS**

Emission Unit Description:

(q) Two (2) portable pumps powered by 350 HP no. 2 diesel fueled engines and mounted on tri-axle trailers, located at the Animal Sciences Research and Education Center, operated intermittently (approximately 500 hours per year each), used for pumping lagoon material to the spray irrigation system and to transfer material from one lagoon to another.

(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.11.1 Sulfur Dioxide Emission Limitations [326 IAC 7-1.1]

Pursuant to Minor Source Modification 157-15944-00012, issued October 21, 2002, 326 IAC 7-1.1-2, and 326 IAC 7-2-1(c), the sulfur dioxide emissions from fuel combustion facilities shall not exceed five-tenths (0.5) pound per million Btu (lb/MMBtu), using a calendar month average, for distillate oil combustion.

Compliance Determination Requirements

D.11.2 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7-4 and in order to demonstrate compliance with Condition D.11.1, fuel sampling and analysis data shall be collected as follows:

(a) The Permittee may rely upon vendor analysis of fuel delivered, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; or,

(b) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with 326 IAC 3-7-4(a).

(1) Oil samples shall be collected from the tanker truck load 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 Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.11.3 Record Keeping Requirements

(a) To document the compliance status with the requirements in Conditions D.11.1 and D.11.2, the Permittee shall maintain records of all fuel sampling and analysis data, pursuant to 326 IAC 7-2. Records and shall be complete and sufficient to establish compliance with the SO_2 limit in Condition D.11.1.

(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

Emission Unit Description:

Insignificant Activities [326 IAC 2-7-1(21)]:

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

Cleaners and solvents characterized as follows: [326 IAC 8-3]

Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100°F) or;

Having a vapor pressure equal to or less than 0.7 kPa; 5mm Hg; or 0.1 psi measured at 20□C (68°F); the use of which for all cleaners and solvents combined does not exceed 145 gallons per 12 months.

(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.12.1 Organic Solvent Degreasing Operations: Cold Cleaner Operation [326 IAC 8-3-2]

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

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a facility for draining cleaned parts;

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

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

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

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

D.12.2 Organic Solvent Degreasing Operations: Cold Cleaner Degreaser Operation and Control [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), for cold cleaner degreaser operations without remote solvent reservoirs, constructed after July 1, 1990, the Permittee shall ensure that the following control equipment requirements are met:

(1) Equip the degreaser with a cover. The cover must be designed so that it can be easily operated with one (1) hand if:

(A) The solvent volatility is greater than two (2) kiloPascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pounds per square inch) measured at thirty-eight degrees Celsius ($38^{O}C$) (one hundred degrees Fahrenheit ($100^{O}F$));

(B) The solvent is agitated; or

(C) The solvent is heated.

(2) Equip the degreaser with a facility for draining cleaned articles. If the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38^{O}C) (one hundred degrees Fahrenheit (100^{O}F)), then the drainage facility must be internal such that articles are enclosed under the cover while draining. The drainage facility may be external for applications where an internal type cannot fit into the cleaning system.

(3) Provide a permanent, conspicuous label which lists the operating requirements outlined in subsection (b).

(4) The solvent spray, if used, must be a solid, fluid stream and shall be applied at a pressure which does not cause excessive splashing.

(5) Equip the degreaser with one (1) of the following control devices if the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38^{O}C) (one hundred degrees Fahrenheit (100^{O}F)), or if the solvent is heated to a temperature greater than forty-eight and nine-tenths degrees Celsius (48.9^{O}C) (one hundred twenty degrees Fahrenheit (120^{O}F)):

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

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

(C) Other systems of demonstrated equivalent control such as a refrigerated chiller of carbon adsorption. Such systems shall be submitted to the U.S. EPA as a SIP revision.

(b) Pursuant to 326 IAC 8-3-5(b) (Cold Cleaner Degreaser Operation and Control), the owner or operator of a cold cleaning facility construction of which commenced after July 1, 1990, shall ensure that the following operating requirements are met:

(1) Close the cover whenever articles are not being handled in the degreaser.

(2) Drain cleaned articles for at least fifteen (15) seconds or until dripping ceases.

(3) Store waste solvent only in covered containers and prohibit the disposal or transfer of waste solvent in any manner in which greater than twenty percent (20%) of the waste solvent by weight could evaporate.

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

Insignificant Activities:
The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations.

(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.13.1 Particulate [326 IAC 6-3-2]

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

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the brazing, cutting, soldering, welding, grinding, and machining operations shall not exceed an amount determined by the following, for a process weight rate equal to or greater than 100 pounds per hour (lb/hr):

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

$E = 4.10\, P^{0.67}$ where E = rate of emission in pounds per hour (lb/hr); and
P = process weight rate in tons per hour (ton/hr).

D.13.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for all brazing equipment, cutting torches, soldering equipment, welding equipment, and grinding and machining operations. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirement

D.13.3 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the particulate control shall be in operation and control emissions from the grinding and machining operations at all times that the associated process is in operation.

SECTION E.1 Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units [326 IAC 12] [40 CFR 60, Subpart Db]

Emission Unit Description:

(c) One (1) circulating fluidized bed coal fired boiler, identified as Boiler 5, with installation completed in 1991, with a nominal capacity of 279 MMBtu/hr, with a baghouse for particulate matter control and limestone injection for sulfur dioxide control, combusting natural gas for ignition, exhausting to stack WADE 05. Boiler 5 has continuous emissions monitoring systems (CEMS) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM).

Under the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Db), Boiler 5 is considered an affected source.

(d) One (1) natural gas fired boiler, identified as Boiler 7, permitted in 2010, with a nominal capacity of 290 MMBtu/hr, exhausting to stack WADE 03. Boiler 7 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) for compliance with NSPS requirements.

Under the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Db), Boiler 7 is considered an affected source.

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

New Source Performance Standards (NSPS) [326 IAC 12] [40 CFR 60]

E.1.1 General Provisions Relating to NSPS [326 IAC 12-1] [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 Boiler 5 and Boiler 7 except when otherwise specified in 40 CFR Part 60, Subpart Db.

E.1.2 Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units [326 IAC 12] [40 CFR 60, Subpart Db]

Pursuant to 40 CFR 60, Subpart Db, the Permittee shall comply with the provisions of the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (included as Attachment A of this permit), which are incorporated by reference as 326 IAC 12 for Boiler 5 and Boiler 7 as specified as follows:

(a) Boiler 5 is subject to the following portions of Subpart Db.

(1) 40 CFR 60.40b(a)
(2) 40 CFR 60.41b
(3) 40 CFR 60.42b(a), (e), (g), and (i)
(4) 40 CFR 60.43b(a), (f), and (g)
(5) 40 CFR 60.44b(a), (h), and (i)
(6) 40 CFR 60.45b
(7) 40 CFR 60.46b
(8) 40 CFR 60.47b
(9) 40 CFR 60.48b
(10) 40 CFR 60.49b

(b) Boiler 7 is subject to the following portions of Subpart Db.

(1) 40 CFR 60.40b(a)
(2) 40 CFR 60.41b

(3) 40 CFR 60.42b(k)(1-2)
(4) 40 CFR 60.44b(h), (i), and (l)(1)
(5) 40 CFR 60.46b
(6) 40 CFR 60.48b
(7) 40 CFR 60.49b

SECTION E.2 Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 [326 IAC 12] [40 CFR 60, Subpart D]

Emission Unit Description:

(b) One (1) natural gas and distillate fuel oil fired boiler, identified as Boiler 3, with installation started in 1973 or 1974 and completed in 1974, with a nominal capacity of 286 MMBtu/hr, exhausting to stack WADE 03. Boiler 3 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Under the Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 NSPS (40 CFR 60, Subpart D), Boiler 3 is considered an affected source.

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

New Source Performance Standards (NSPS) [326 IAC 12] [40 CFR 60]

E.2.1 General Provisions Relating to NSPS [326 IAC 12-1] [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 Boiler 3 except when otherwise specified in 40 CFR Part 60, Subpart D.

E.2.2 Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 [326 IAC 12] [40 CFR 60, Subpart D]

Pursuant to 40 CFR 60, Subpart D, the Permittee shall comply with the provisions of the Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 (included as Attachment B of this permit), which are incorporated by reference as 326 IAC 12 for Boiler 3 as specified as follows:

(1) 40 CFR 60.40(a)(1) and (c)
(2) 40 CFR 60.41
(3) 40 CFR 60.42(a) and (c)
(4) 40 CFR 60.43(a)(1)and (b-d)
(5) 40 CFR 60.44(a)(1-2), (b), and (e)
(6) 40 CFR 60.45
(7) 40 CFR 60.46

E.2.3 Alternative Opacity Requirement [326 IAC 12] [40 CFR 60, Subpart D]

Pursuant to the U.S. EPA letter dated September 16, 2004, the Permittee may operate Boiler 3 without a continuous opacity monitoring (COM) system provided the following requirements are met:

(a) The usage of distillate fuel oil in Boiler 3 shall be limited to 500,000 U.S. gallons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) Any change in the type of fuel oil used in Boiler 3, other than distillate fuel oil and natural gas, must be approved by IDEM, OAQ.

(c) An observer certified in accordance with EPA Method 9 shall perform 6-minute visible emissions observations at least once per day during daylight hours when distillate fuel oil is burned in Boiler 3.

(d) If the average opacity for a 6-minute set of visible emissions observations made exceeds ten (10) percent, the observer shall collect two additional 6-minute sets of visible emissions observations for a total of three data sets. If excess emissions occur during the three 6-minute sets of visible emissions observations, the observer shall collect additional 6-minute sets of visible emissions observations until excess emissions do not occur during three (3) consecutive 6-minute sets of visible emissions observations. Boiler 3 may be repaired or adjusted before the additional visible emissions observations are conducted.

E.2.4 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition E.2.3 shall be submitted 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 E.3 Standards of Performance for Coal Preparation Plants [326 IAC 12] [40 CFR 60, Subpart Y]

Emission Unit Description:

(h) One (1) coal storage and handling system identified as COAL Segment 2, installed in 1996, with a nominal capacity of 107 tons/hr, including: truck unloading and two (2) in-ground hoppers, two (2) vibratory feeders; one (1) totally enclosed tubular conveyor identified as BC-1 equipped with a magnetic separator and with emissions controlled by a baghouse exhausting to stack CV1; one (1) transfer enclosure with one (1) coal sampler, with emissions controlled by a baghouse exhausting to stack CV2; and one (1) totally enclosed tubular conveyor identified as BC-2 terminating at the top of Wade Utility Plant, with emissions from the final transfer point controlled by a baghouse exhausting to stack CV3. Coal is fed to the bunkers for Boiler 1, Boiler 2, and to the pre-crusher ahead of the indoor storage silo for Boiler 5. Emissions from the Boiler 1 and Boiler 2 bunkers are controlled by a RotoClone for each of the two (2) bunkers. The bunker for Boiler 1 exhausts to stack CB1. The bunker for Boiler 2 exhausts to CB2.

(j) One (1) coal preparation system for Boiler 5, with installation completed in 1991, with a nominal capacity of 12.68 tons/hr, including: one (1) enclosed 125 ton/hr Redler conveyor with one (1) enclosed pre-crusher (both serving in a back-up capacity), one (1) 150 ton/hr enclosed belt conveyor and pre-crusher with installation completed in 2009. Both lines feed into one (1) coal storage bunker, two (2) weigh belt feeders; and two (2) enclosed crushers with emission directed to a baghouse exhausting to stack CB5.

Under the Standards of Performance for Coal Preparation Plants NSPS (40 CFR 60, Subpart Y), the coal preparation system for Boiler 5 including the crushers and COAL Segment 2 are considered affected sources.

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

New Source Performance Standards (NSPS) [326 IAC 12] [40 CFR 60]

E.3.1 General Provisions Relating to NSPS [326 IAC 12-1] [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 coal preparation system for Boiler 5 including the crushers and COAL Segment 2 except when otherwise specified in 40 CFR Part 60, Subpart Y.

E.3.2 Standards of Performance for Coal Preparation Plants [326 IAC 12] [40 CFR 60, Subpart Y]

Pursuant to 40 CFR 60, Subpart Y, the Permittee shall comply with the provisions of the Standards of Performance for Coal Preparation Plants (included as Attachment C of this permit), which are incorporated by reference as 326 IAC 12 for the coal preparation system for Boiler 5 including the crushers and COAL Segment 2 as specified as follows:

(1) 40 CFR 60.250
(2) 40 CFR 60.251
(3) 40 CFR 60.254
(4) 40 CFR 60.255
(5) 40 CFR 60.257
(6) 40 CFR 60.258

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2013, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 75 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

(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 [40 CFR 60, Subpart KKKK]

E.4.1 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 combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, except as otherwise specified in 40 CFR Part 60, Subparts KKKK.

E.4.2 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 natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 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
20. Table 1

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2013, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 75 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

(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 [40 CFR 63, Subpart YYYY]

E.5.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines [326 IAC 20-1][40 CFR Part 63, Subpart A]

Pursuant to 40 CFR 63.6090, 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 YYYY, in accordance with the schedule in 40 CFR 63 Subpart YYYY.

E.5.2 National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines [40 CFR Part 63, Subpart YYYY][326 IAC 20]

Pursuant to CFR Part 63, Subpart, the Permittee shall comply with the provisions of 40 CFR Subpart 63, for the affected source, as specified as follows:

1. 40 CFR 63.6080
2. 40 CFR 63.6085
3. 40 CFR 63.6090
4. 40 CFR 63.6092
5. 40 CFR 63.6095
6. 40 CFR 63.6100
7. 40 CFR 63.6105
8. 40 CFR 63.6110
9. 40 CFR 63.6115
10. 40 CFR 63.6120
11. 40 CFR 63.6125
12. 40 CFR 63.6130
13. 40 CFR 63.6135
14. 40 CFR 63.6140
15. 40 CFR 63.6150
16. 40 CFR 63.6155
17. 40 CFR 63.6160
18. 40 CFR 63.6165
19. 40 CFR 63.6170
20. 40 CFR 63.6175
21. Table 1 to Subpart YYYY of Part 63
22. Table 2 to Subpart YYYY of Part 63
23. Table 3 to Subpart YYYY of Part 63

24. Table 4 to Subpart YYYY of Part 63
25. Table 5 to Subpart YYYY of Part 63
26. Table 6 to Subpart YYYY of Part 63
27. Table 7 to Subpart YYYY of Part 63

SECTION F Clean Air Interstate Rule (CAIR) Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-3-1(a)

ORIS Code: 50240

CAIR Permit for CAIR Units Under 326 IAC 24-3-1(a)

After the startup of Boiler 7 this boiler, identified as Boiler 1 shall be decommissioned within one hundred and eighty (180) days:

(a1) One (1) spreader stoker coal fired boiler, identified as Boiler 1, with installation completed in 1960, with a nominal capacity of 281 MMBtu/hr, with a multi-cyclone collector and an electrostatic precipitator for particulate matter control, exhausting to stack WADE 01. Boiler 1 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After the fuel change from coal to natural gas in Boiler 2, the coal usage shall be discontinued in this boiler, identified as Boiler 2:

(b1) One (1) spreader stoker coal fired boiler, identified as Boiler 2, with installation completed in 1967, with a nominal capacity of 274 MMBtu/hr, with a multi-cyclone collector and a multi-compartment baghouse for particulate matter control, exhausting to stack WADE 02. Boiler 2 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After fuel Change to Natural Gas:

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in 2013, with a maximum heat input capacity of 315 MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

(c) One (1) natural gas and distillate fuel oil fired boiler, identified as Boiler 3, with installation started in 1973 or 1974 and completed in 1974, with a nominal capacity of 286 MMBtu/hr, exhausting to stack WADE 03. Boiler 3 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

(d) One (1) circulating fluidized bed coal fired boiler, identified as Boiler 5, with installation started in 1989 and completed in 1991, with a nominal capacity of 279 MMBtu/hr, with a baghouse for particulate matter control and limestone injection for sulfur dioxide control, combusting natural gas for ignition, exhausting to stack WADE 05. Boiler 5 has continuous emissions monitoring systems (CEMS) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM).

(e) One (1) natural gas fired boiler, identified as Boiler 7, permitted in 2010, with a nominal capacity of 290 MMBtu/hr, exhausting to stack WADE 03. Boiler 7 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) for compliance with NSPS requirements.

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

F.1 Automatic Incorporation of Definitions [326 IAC 24-3-7(e)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-3-2.

F.2 Standard Permit Requirements [326 IAC 24-3-4(a)] [40 CFR 97.306(a)]

(a) The owners and operators of each CAIR NO_X ozone season source and CAIR NO_X ozone season unit shall operate each source and unit in compliance with this CAIR permit.

(b) The CAIR NO_X ozone season units subject to this CAIR permit are Boiler 1, Boiler 2, Boiler 3, Boiler 5, and Boiler 7.

F.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-3-4(b)] [40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NO_X ozone season source and CAIR NO_X ozone season unit at the source shall comply with the applicable monitoring, reporting, and record keeping requirements of 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NO_X ozone season source with the CAIR NO_X ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition F.4, Nitrogen Oxides Ozone Season Emission Requirements.

F.4 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 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.

F.5 Excess Emissions Requirements [326 IAC 24-3-4(d)] [40 CFR 97.306(d)]

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:

(a) Surrender the CAIR NO_X ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).

(b) 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.

F.6 Record Keeping Requirements [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.306(e)]

Unless otherwise provided, the owners and operators of the CAIR NO_X ozone season source and each 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 24-3-6(h) for the CAIR designated representative for the source and each 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 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-3-11, provided that to the extent that 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 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 ozone season trading program or to demonstrate compliance with the requirements of the 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. Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

F.7 Reporting Requirements [326 IAC 24-3-4(e)] [40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NO_X ozone season source and each CAIR NO_X ozone season unit at the source shall submit the reports required under the CAIR NO_X ozone season trading program, including those under 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-3-4(e) and 326 IAC 24-3-6(e)(1), each submission under the 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 24-3 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 24-3 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

F.8 Liability [326 IAC 24-3-4(f)] [40 CFR 97.306(f)]

The owners and operators of each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit shall be liable as follows:

(a) Each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit shall meet the requirements of the CAIR NO_X ozone season trading program.

(b) Any provision of the C CAIR NO_X ozone season trading program that applies to a CAIR NO_X ozone season source or the CAIR designated representative of a CAIR NO_X ozone season source shall also apply to the owners and operators of such source and of the CAIR NO_X ozone season units at the source.

(c) Any provision of the CAIR NO_X ozone season trading program that applies to a CAIR NO_X ozone season unit or the CAIR designated representative of a CAIR NO_X ozone season unit shall also apply to the owners and operators of such unit.

F.9 Effect on Other Authorities [326 IAC 24-3-4(g)] [40 CFR 97.306(g)]

No provision of the CAIR NO_X ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 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 ozone season source or 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).

F.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-3-6] [40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-3-6(f)(3), each CAIR NO_X ozone season source, including all 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 ozone season trading program concerning the source or any CAIR NO_X ozone season unit at the source.

(b) The provisions of 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_X ozone season source choose to designate an alternate CAIR designated representative.

Except as specified in 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:	Purdue University
Source Address:	401 S. Grant Street, Freehafer Hall of Administrative Services,West Lafayette, Indiana, 47907-2024
Part 70 Permit Renewal No.:	T 157-27313-00012

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify): ____________________

☐ Report (specify): ____________________

☐ Notification (specify): ____________________

☐ Affidavit (specify): ____________________

☐ Other (specify): ____________________

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Signature:
Printed Name:
Title/Position:
Phone:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

100 North Senate Avenue
MC 61-53, IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: 317-233-0178
Fax: 317-233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name:	Purdue University
Source Address:	401 S. Grant Street, Freehafer Hall of Administrative Services,West Lafayette, Indiana, 47907-2024
Part 70 Permit Renewal No.:	T 157-27313-00012

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), no later than four (**4**) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance and Enforcement Branch); and
- The Permittee must submit notice in writing or by facsimile no later than 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: ______________________________

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

Part 70 Quarterly Report

Source Name: Purdue University
Emission Unit Location: Purdue University, Wade Utility Plant, West Lafayette, Indiana, 47907-2024
Part 70 Permit Renewal No.: T 157-27313-00012
Facility: Boiler 2
Parameter: Natural gas usage
Limit: less than 2,791 million cubic feet per twelve (12) consecutive month period

QUARTER : **YEAR:**

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

☐ No deviation occurred in this quarter.

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

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

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

Fuel Oil-Fired Electric Generator (BSG) - Part 70 Quarterly Report

Source Name: Purdue University
Emission Unit Location: Purdue University, Wade Utility Plant, West Lafayette, Indiana, 47907-2024
Part 70 Permit Renewal No.: T 157-27313-00012
Facility: 17.7 MMBtu/hr electric generator, BSG
Parameter: no. 2 fuel oil usage
Limit: less than 113,000 gallons per 12 consecutive month period

YEAR: _____

Month	No. 2 Fuel Oil Usage for This Month (gallons)	No. 2 Fuel Oil Usage for Previous 11 Months (gallons)	No. 2 Fuel Oil Usage for 12-Month Period (gallons)

☐ No deviation occurred in this quarter.

☐ Deviations 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

Boiler 3 Fuel Usage Limit - Part 70 Quarterly Report

Source Name: Purdue University
Emission Unit Location: Purdue University, Wade Utility Plant, West Lafayette, Indiana, 47907-2024
Part 70 Permit Renewal No.: T 157-27313-00012
Facility: 286 MMBtu/hr Boiler (Boiler 3)
Parameter: distillate fuel oil usage (opacity)
Limit: The usage of distillate fuel oil in Boiler 3 shall be limited to 500,000 U.S. gallons per twelve (12) consecutive month period, with compliance determined at the end of each month.

YEAR: _____

Month	Distillate Fuel Oil Usage for This Month (gallons)	Distillate Fuel Oil Usage for Previous 11 Months (gallons)	Distillate Fuel Oil Usage for 12-Month Period (gallons)

☐ No deviation occurred in this quarter.

☐ Deviations occurred in this quarter.
Deviation has been reported on: ____________________

Submitted By: ______________________________

Title/Position: ______________________________

Signature: ______________________________

Date: ______________________________

Phone: ______________________________

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

PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Purdue University
Source Address: 401 S. Grant Street, Freehafer Hall of Administrative Services,West Lafayette, Indiana, 47907-2024
Part 70 Permit Renewal No.: T 157-27313-00012

Months: __________ **to** __________ **Year:** ________

Page 1 of 2

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

Page 2 of 2

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

Form Completed By: ______________________________

Title/Position: ______________________________

Date: ______________________________

Phone: ______________________________

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

Source Description and Location

Source Name:	Purdue University - West Lafayette
Source Location:	401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, IN 47907
County:	Tippecanoe
SIC Code:	8221
Operation Permit Renewal No.:	T 157-27313-00012
Permit Reviewer:	Kimberly Cottrell

NSPS [40 CFR Part 60, Subpart Db]

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

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

§ 60.40b Applicability and delegation of authority.

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

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

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

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

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

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

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J (§60.104).

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

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

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

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

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

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

(i)

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

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

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

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

§ 60.41b Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Natural gas means:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.42b Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction) and the emission limit determined according to the following formula:

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

Where:

E_s= SO_2emission limit, in ng/J or lb/MMBtu heat input;

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

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

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

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

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

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 50 percent of the potential SO_2emission rate (50 percent reduction) and that contain SO_2in excess of the emission limit determined according to the following formula:

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.43b Standard for particulate matter (PM).

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

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

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

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

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

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

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

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

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

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2or PM emissions is not subject to the PM limits in (h)(1) of this section.

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

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

§ 60.44b Standard for nitrogen oxides (NOX).

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

%P_s= Potential SO_2emission rate, percent;

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

Where:

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

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

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

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

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2emission limits under §60.42b.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) For determination of PM emissions, the oxygen (O_2) or CO_2sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

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

(i) The O_2or CO_2measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

(ii) Method 7E of appendix A of this part shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2concentration.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

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

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

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

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

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

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

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

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

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$and either O_2or CO_2concentrations shall both be monitored at the inlet and outlet of the SO_2control device. If the owner or operator has installed and certified $SO_2$and O_2or CO_2CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2concentration data and CO_2(or O_2) data are collected simultaneously; and

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

(3) The reporting requirements of §60.49b are met. $SO_2$and CO_2(or O_2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2input rate, or

(2) Measuring SO_2according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$and CO_2measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2emission rate, E_D, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A–8) and stated in ng/J (lb/MMBtu) heat input.

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

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

(d) The 1-hour average SO_2emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

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

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

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

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential SO_2emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2control device is 50 percent of the maximum estimated hourly potential SO_2emissions of the fuel combusted. Alternatively, SO_2span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

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

(i) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_X span values less than or equal to 30 ppm; and

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

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

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

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

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

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

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

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

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

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 30 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 30 calendar days according to the requirements in §60.46d(d)(7).

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

z = Fraction of total heat input derived from coal.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.49b Reporting and recordkeeping requirements.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar date;

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

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

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

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

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

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

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

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

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

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

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

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

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

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

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

(m) For each affected facility subject to the SO_2 standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

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

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

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

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

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

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

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

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b(i).

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_X standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

Air ratio control damper is defined as the part of the low NO_X burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_X technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_X standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_X standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO $_X$*. (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO $_X$*. (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements*. (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

Attachment B – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971 [326 IAC 12] [40 CFR Part 60, Subpart D]

Source Description and Location

Source Name:	Purdue University - West Lafayette
Source Location:	401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, IN 47907
County:	Tippecanoe
SIC Code:	8221
Operation Permit Renewal No.:	T 157-27313-00012
Permit Reviewer:	Kimberly Cottrell

NSPS [40 CFR Part 60, Subpart D]

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

Source: 72 FR 32717, June 13, 2007, unless otherwise noted.

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBtu/hr).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under subpart Da is not covered under this subpart.

§ 60.41 Definitions.

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

Boiler 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 steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see §60.17).

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

Fossil-fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

§ 60.42 Standard for particulate matter (PM).

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb/MMBtu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

(c) As an alternate to meeting the requirements of paragraph (a) of this section, an owner or operator that elects to install, calibrate, maintain, and operate a continuous emissions monitoring systems (CEMS) for measuring PM emissions can petition the Administrator (in writing) to comply with §60.42Da(a) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.43Da(a) of subpart Da of this part.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.43 Standard for sulfur dioxide (SO_2).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y\,(340) + z\,(520)}{(y + z)}$$

Where:

$PS_{SO}2$= Prorated standard for $S_{O2}$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.43Da(i)(3) of subpart Da of this part or comply with §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.43Da(i)(3) of subpart Da of this part or §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.44 Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_X, expressed as NO_2in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.

(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w\,(260) + x\,(86) + y\,(130) + z\,(300)}{(w + x + y + z)}$$

Where:

PS_{NOX}= Prorated standard for $NO_X$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

x = Percentage of total heat input derived from gaseous fossil fuel;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO_Xdoes not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.44Da(e)(3) of subpart Da of this part.

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a CEMS for measuring SO2emissions, NOXemissions, and either oxygen (O2) or carbon dioxide (CO2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that burns only gaseous or liquid fossil fuel (excluding residual oil) with potential SO2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO2or PM, CEMS for measuring the opacity of emissions and SO2 emissions are not required if the owner or operator monitors SO2emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2emissions is not required if the owner or operator monitors SO_2emissions by fuel sampling and analysis.

(3) Notwithstanding §60.13(b), installation of a CEMS for NO_Xmay be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of $NO_X$are less than 70 percent of the applicable standards in §60.44, a CEMS for measuring NO_Xemissions is not required. If the initial performance test results show that NO_Xemissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_Xwithin one year after the date of the initial performance tests under §60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any CEMS for sulfur oxides and NO_X, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a CEMS for measuring either O_2or $CO_2$is not required.

(5) An owner or operator may petition the Administrator (in writing) to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.

(6) A CEMS for measuring the opacity of emissions is not required for a fossil fuel-fired steam generator 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 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

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

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

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

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

(ii) You must calculate the 1-hour average CO emissions levels for each boiler 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 boiler operating day.

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

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) 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.

(7) The owner or operator of an affected facility subject to an opacity standard under §60.42 and that elects to not install a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section 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 §60.42 and shall comply with either paragraphs (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(i) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) 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 (b)(7) of this section according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) 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;

(B) 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;

(C) 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

(D) 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 30 calendar days from the date that the most recent performance test was conducted.

(ii) 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 test, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of this section.

(A) 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 (b)(7) of this section within 30 calendar days according to the requirements in §60.46(b)(3).

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

(iii) 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 (b)(7)(ii) 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.

(c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or $NO_X$the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, $SO_2$and NO_Xspan values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	([1])	500.
Liquid	1,000	500.
Solid	1,500	1,000.
Combinations	1,000y + 1,500z	500 (x + y) + 1,000z.

[1]Not applicable.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel;

y = Fraction of total heat input derived from liquid fossil fuel; and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the $SO_2$and NO_Xspan values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring $O_2$is selected, the measurement of the pollutant concentration and O_2concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/MMBtu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(3) $\%O_2$, $\%CO_2$ = O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = $2,723 \times 10^{-17}$dscm/J (10,140 dscf/MMBtu) and F_c = 0.532×10^{-17}scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.637×10^{-7}dscm/J (9,820 dscf/MMBtu) and F_c = 0.486×10^{-7}scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7}dscm/J (9,220 dscf/MMBtu) and F_c = 0.384×10^{-7}scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7}dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c = 0.279×10^{-7}scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7}scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7}scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589×10^{-7}dscm/J (9,640 dscf/MMBtu) and F_c = 0.500×10^{-7}scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492×10^{-7}dscm/J (9,280 dscf/MMBtu) and F_c = 0.494×10^{-7}scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.659×10^{-7}dscm/J (9,900 dscf/MMBtu) and F_c = 0.516×10^{-7}scm CO_2/J (1,920 scf CO_2/MMBtu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\,\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5} (\%C)}{GCV\ (\text{SI units})}$$

$$F = 10^{-6}\,\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (\text{English units})}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (\text{SI units})}$$

$$F_c = \frac{321 \times 10^{3}\ (\%C)}{GCV\ (\text{English units})}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see §60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:

X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

$F_i$or $(F_c)_i$= Applicable F or $F_c$factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity* . Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of §60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of §60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:

(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2as measured by a CEMS exceed the applicable standard in §60.43; or

(ii) For affected facilities electing to comply with §60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2as measured by a CEMS exceed the applicable standard in §60.43. Facilities complying with the 30-day SO_2standard shall use the most current associated SO_2compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part or §§60.45b and 60.47b of subpart Db of this part, as applicable.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring $NO_X$are defined as:

(i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44; or

(ii) For affected facilities electing to comply with §60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_Xas measured by a CEMS exceed the applicable standard in §60.44. Facilities complying with the 30-day NO_Xstandard shall use the most current associated NO_Xcompliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter.* Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in §60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§60.48Da and 60.49Da of subpart Da of this part.

(h) The owner or operator of an affected facility subject to the opacity limits in §60.42 that elects to monitor emissions according to the requirements in §60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(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 (h)(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 (h)(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.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO_2, and NO_Xstandards in §§60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, SO_2, or NO_Xshall be computed for each run using the following equation:

$$E = CF_d\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where:

E = Emission rate of pollutant, ng/J (1b/million Btu);

C = Concentration of pollutant, ng/dscm (1b/dscf);

$\%O_2$= O_2concentration, percent dry basis; and

F_d= Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the SO_2concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration (%O_2). The O_2sample shall be taken simultaneously with, and at the same point as, the SO_2sample. The SO_2emission rate shall be computed for each pair of $SO_2$and O_2samples. The SO_2emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration.

(i) The sampling site and location shall be the same as for the SO_2sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_Xsample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_Xsample.

(iii) The NO_Xemission rate shall be computed for each pair of $NO_X$and O_2samples. The NO_Xemission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see §60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of PM, $SO_2$and NO_Xmay be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = CF_c \left(\frac{100}{\%CO_2} \right)$$

Where:

E = Emission rate of pollutant, ng/J (lb/MMBtu);

C = Concentration of pollutant, ng/dscm (lb/dscf);

$\%CO_2$= CO_2concentration, percent dry basis; and

F_c= Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(ii) If and only if the average Fc factor in Method 19 of appendix A of this part is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the $O_2$and CO_2concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o(average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average $F_o$value, as determined from the average values of $F_d$and $F_c$in Method 19 of appendix A of this part, *i.e.* , F_{oa}= 0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When $F_o$is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When $F_o$is less than 0.97 $F_{oa}$and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When $F_o$is greater than 1.03 $F_{oa}$and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, *e.g.* , if $F_o$is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used with Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of SO_2(including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO_2emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2concentration ($\%O_2$) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5078, Jan. 28, 2009]

Attachment C – Standards of Performance for Coal Preparation Plants [326 IAC 12] [40 CFR Part 60, Subpart Y]

Source Description and Location

Source Name:	Purdue University - West Lafayette
Source Location:	401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, IN 47907
County:	Tippecanoe
SIC Code:	8221
Operation Permit Renewal No.:	T 157-27313-00012
Permit Reviewer:	Kimberly Cottrell

NSPS [40 CFR Part 60, Subpart Y]

Subpart Y—Standards of Performance for Coal Preparation Plants

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart.

[42 FR 37938, July 25, 1977; 42 FR 44812, Sept. 7, 1977, as amended at 65 FR 61757, Oct. 17, 2000]

§ 60.251 Definitions.

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

(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(c) *Coal* means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(d) *Cyclonic flow* means a spiraling movement of exhaust gases within a duct or stack.

(e) *Thermal dryer* means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) *Pneumatic coal-cleaning equipment* means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

[41 FR 2234, Jan. 15, 1976, as amended at 48 FR 3738, Jan. 27, 1983; 65 FR 61757, Oct. 17, 2000]

§ 60.252 Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

(1) Contain particulate matter in excess of 0.040 g/dscm (0.017 gr/dscf).

(2) Exhibit 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

[41 FR 2234, Jan. 15, 1976, as amended at 65 FR 61757, Oct. 17, 2000]

§ 60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under §60.13(b).

[41 FR 2234, Jan. 15, 1976, as amended at 54 FR 6671, Feb. 14, 1989; 65 FR 61757, Oct. 17, 2000]

§ 60.254 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particular matter standards in §60.252 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

(2) Method 9 and the procedures in §60.11 shall be used to determine opacity.

[54 FR 6671, Feb. 14, 1989]

Attachment D – Standards of Performance for Stationary Combustion Turbines [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

Source Description and Location

Source Name:	Purdue University - West Lafayette
Source Location:	401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, IN 47907
County:	Tippecanoe
SIC Code:	8221
Operation Permit Renewal No.:	T 157-27313-00012
Permit Reviewer:	Josiah Balogun

NSPS [40 CFR Part 60, Subpart KKKK]

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_Xemission 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_Xspecified 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_2in 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_2in 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_2in 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_Xemissions 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_Xemissions, 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_Xmonitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_Xemission 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_Xemission 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_2concentration exceeds 19.0 percent O_2(or the hourly average CO_2concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2or 1.0 percent CO_2(as applicable) may be used in the emission calculations.

(c) Correction of measured NO_Xconcentrations to 15 percent $O_2$is not allowed.

(d) If you have installed and certified a NO_Xdiluent 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_Xemission 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:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad (Eq. 1)$$

Where:

E = hourly NO_Xemission rate, in lb/MWh,

$(NO_X)_h$= hourly NO_Xemission 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

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (\text{Eq. } 3)$$

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:

$$E = \frac{(NO_x)_m}{BL * AL} \qquad (\text{Eq. } 4)$$

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_Xemission 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_Xemission 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_Xemission 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_X limit 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_X limit 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_X performance 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_X concentration (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_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad (Eq.\ 5)$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X 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

(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_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission 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_Xemissions 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_Xcontrol 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_Xemission 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_Xemission 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_Xemission 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_Xemission 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_Xemission 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_2performance 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_2concentration (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_2emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad (Eq. 6)$$

Where:

E = SO_2emission rate, in lb/MWh

1.664×10^{-7}= conversion constant, in lb/dscf-ppm

$(SO_2)_c$= average SO_2concentration 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_2emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2emission 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_Xemissions 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	> 850 MMBtu/h	15 ppm at 15 percent

natural gas		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 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful 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_2 or 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_2 or 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_2 or 110 ng/J of useful output (0.86 lb/MWh).

Attachment E – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines [326 IAC 20] [40 CFR Part 63, Subpart YYYY]

Source Description and Location

Source Name:	Purdue University - West Lafayette
Source Location:	401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, IN 47907
County:	Tippecanoe
SIC Code:	8221
Operation Permit Renewal No.:	T 157-27313-00012
Permit Reviewer:	Josiah Balogun

NESHAP [40 CFR Part 63, Subpart YYYY]

Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Source: 69 FR 10537, Mar. 5, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6080 What is the purpose of subpart YYYY?

Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

§ 63.6085 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) 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), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

(b) A major source of HAP emissions is a contiguous site under common control 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.

§ 63.6090 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 combustion turbine located at a major source of HAP emissions.

(1) *Existing stationary combustion turbine.* A stationary combustion turbine is existing if you commenced construction or reconstruction of the stationary combustion turbine on or before January 14, 2003. A change in ownership of an existing stationary combustion turbine does not make that stationary combustion turbine a new or reconstructed stationary combustion turbine.

(2) *New stationary combustion turbine.* A stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

(3) *Reconstructed stationary combustion turbine.* A stationary combustion turbine is reconstructed if you meet the definition of reconstruction in §63.2 of subpart A of this part and reconstruction is commenced after January 14, 2003.

(b) *Subcategories with limited requirements.* (1) A new or reconstructed stationary combustion turbine located at a major source which meets either of the following criteria does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6145(d):

(i) The stationary combustion turbine is an emergency stationary combustion turbine; or

(ii) The stationary combustion turbine is located on the North Slope of Alaska.

(2) A stationary combustion turbine which burns landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified municipal solid waste (MSW) is used to generate 10 percent or more of the gross heat input on an annual basis does not have to meet the requirements of this subpart except for:

(i) The initial notification requirements of §63.6145(d); and

(ii) Additional monitoring and reporting requirements as provided in § §63.6125(c) and 63.6150.

(3) An existing, new, or reconstructed stationary combustion turbine with a rated peak power output of less than 1.0 megawatt (MW) at International Organization for Standardization (ISO) standard day conditions, which is located at a major source, does not have to meet the requirements of this subpart and of subpart A of this part. This determination applies to the capacities of individual combustion turbines, whether or not an aggregated group of combustion turbines has a common add-on air pollution control device. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification. For example, a 0.75 MW emergency turbine would not have to submit an initial notification.

(4) Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

(5) Combustion turbine engine test cells/stands do not have to meet the requirements of this subpart but may have to meet the requirements of subpart A of this part if subject to another subpart. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification.

§ 63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?

No, duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation.

§ 63.6095 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you start up a new or reconstructed stationary combustion turbine which is a lean premix oil-fired stationary combustion turbine or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart on or before March 5, 2004, you must comply with the emissions limitations and operating limitations in this subpart no later than March 5, 2004.

(2) If you start up a new or reconstructed stationary combustion turbine which is a lean premix oil-fired stationary combustion turbine or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart after March 5, 2004, you must comply with the emissions limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If your new or reconstructed stationary combustion turbine is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, it must be in compliance with any applicable requirements of this subpart when it becomes a major source.

(c) You must meet the notification requirements in §63.6145 according to the schedule in §63.6145 and in 40 CFR part 63, subpart A.

(d) *Stay of standards for gas-fired subcategories.* If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in theFederal Register.

[69 FR 10537, Mar. 5, 2004, as amended at 69 FR 51188, Aug. 18, 2004]

Emission and Operating Limitations

§ 63.6100 What emission and operating limitations must I meet?

For each new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, you must comply with the emission limitations and operating limitations in Table 1 and Table 2 of this subpart.

General Compliance Requirements

§ 63.6105 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations which apply to you at all times except during startup, shutdown, and malfunctions.

(b) If you must comply with emission and operating limitations, you must operate and maintain your stationary combustion turbine, oxidation catalyst emission control device or other 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.

Testing and Initial Compliance Requirements

§ 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?

(a) You must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 calendar days after the compliance date that is specified for your stationary combustion turbine in §63.6095 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (b)(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.

§ 63.6115 When must I conduct subsequent performance tests?

Subsequent performance tests must be performed on an annual basis as specified in Table 3 of this subpart.

§ 63.6120 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Table 3 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements of the General Provisions at §63.7(e)(1) and under the specific conditions in Table 2 of this subpart.

(c) Do not conduct performance tests or compliance evaluations during periods of startup, shutdown, or malfunction. Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent.

(d) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour.

(e) If your stationary combustion turbine is not equipped with an oxidation catalyst, you must petition the Administrator for operating limitations that you will monitor to demonstrate compliance with the formaldehyde emission limitation in Table 1. You must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, you may petition the Administrator for approval of no additional operating limitations. If you submit a petition under this section, you must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.

(f) If your stationary combustion turbine is not equipped with an oxidation catalyst and you petition the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in Table 1, your petition must include the following information described in paragraphs (f)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as additional 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.

(g) If you petition the Administrator for approval of no additional operating limitations, your petition must include the information described in paragraphs (g)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary combustion turbine 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 why establishing limitations on the parameters is not possible;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why you could not establish upper and/or lower values for the parameters which would establish limits on the parameters as operating limitations;

(5) For the parameters which could change in such a way as to increase HAP emissions, 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, unreasonable or unnecessary to adopt the parameters as operating limitations.

§ 63.6125 What are my monitor installation, operation, and maintenance requirements?

(a) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you use an oxidation catalyst emission control device, you must monitor on a continuous basis your catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(b) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you are not using an oxidation catalyst, you must continuously monitor any parameters specified in your approved petition to the Administrator, in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(c) If you are operating a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 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 turbine in a manner which minimizes HAP emissions.

(d) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must monitor and record your distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-resettable hour meter to measure the number of hours that distillate oil is fired.

§ 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 4 of this subpart.

(b) You must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in §63.6145(f).

Continuous Compliance Requirements

§ 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating.

(b) Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

§ 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 1 and Table 2 of this subpart according to methods specified in Table 5 of this subpart.

(b) You must report each instance in which you did not meet each emission imitation or operating limitation. You must also report each instance in which you did not meet the requirements in Table 7 of 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 §63.6150.

(c) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in accordance with §63.6(e)(1)(i).

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006]

Notifications, Reports, and Records

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in §63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with §63.6090(b), your notification must include the information in §63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in §63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

§ 63.6150   What reports must I submit and when?

(a) Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of this subpart. The semiannual compliance report must contain the information described in paragraphs (a)(1) through (a)(4) of this section. The semiannual compliance report must be submitted by the dates specified in paragraphs (b)(1) through (b)(5) of this section, unless the Administrator has approved a different schedule.

(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) For each deviation from an emission limitation, the compliance report must contain the information in paragraphs (a)(4)(i) through (a)(4)(iii) of this section.

(i) The total operating time of each stationary combustion turbine during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(b) Dates of submittal for the semiannual compliance report are provided in (b)(1) through (b)(5) of this section.

(1) The first semiannual compliance report must cover the period beginning on the compliance date specified in §63.6095 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 specified in §63.6095.

(2) The first semiannual 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 in §63.6095.

(3) Each subsequent semiannual 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) Each subsequent semiannual 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 combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual 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 (4) of this section.

(c) If you are operating as a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (c)(1) through (c)(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, digester gas, or gasified MSW 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.

(d) Dates of submittal for the annual report are provided in (d)(1) through (d)(5) of this section.

(1) The first annual report must cover the period beginning on the compliance date specified in §63.6095 and ending on December 31.

(2) The first annual report must be postmarked or delivered no later than January 31.

(3) Each subsequent annual report must cover the annual reporting period from January 1 through December 31.

(4) Each subsequent annual report must be postmarked or delivered no later than January 31.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual 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 (d)(1) through (4) of this section.

(e) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (e)(1) through (e)(3) of this section.

(1) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.

(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.

§ 63.6155 What records must I keep?

(a) You must keep the records as described in paragraphs (a)(1) through (5).

(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 requirements in §63.10(b)(2)(xiv).

(2) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(3) Records of the occurrence and duration of each startup, shutdown, or malfunction as required in §63.10(b)(2)(i).

(4) Records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable, as required in §63.10(b)(2)(ii).

(5) Records of all maintenance on the air pollution control equipment as required in §63.10(b)(iii).

(b) If you are operating a stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis, or if you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must keep the records of your daily fuel usage monitors.

(c) You must keep the records required in Table 5 of this subpart to show continuous compliance with each operating limitation that applies to you.

§ 63.6160   In what form and how long must I keep my records?

(a) You must maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection 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 retain your records of the most recent 2 years on site or your records must be accessible on site. Your records of the remaining 3 years may be retained off site.

Other Requirements and Information

§ 63.6165   What parts of the General Provisions apply to me?

Table 7 of this subpart shows which parts of the General Provisions in §63.1 through 15 apply to you.

§ 63.6170   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 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 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the EPA Administrator 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 emission limitations or operating limitations in §63.6100 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 to determine outlet formaldehyde concentration, as specified in §63.6110(b).

§ 63.6175 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA; in 40 CFR 63.2, the General Provisions of this part; and in this section:

Area source means any stationary source of HAP that is not a major source as defined in this part.

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 reciprocating internal combustion engines.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101–549, 104 Stat. 2399).

Cogeneration cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger, such as a heat recovery steam generator.

Combined cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to generate steam for use in a steam turbine.

Combustion turbine engine test cells/stands means engine test cells/stands, as defined in subpart PPPPP of this part, that test stationary combustion turbines.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

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;

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart; or

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diffusion flame gas-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire gas using diffusion flame technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Diffusion flame gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Diffusion flame oil-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Diffusion flame oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Diffusion flame technology means a configuration of a stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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.

Distillate oil 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.

Emergency stationary combustion turbine means any stationary combustion turbine that 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 stationary 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 stationary combustion turbines.

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 pollutant (HAP) means any air pollutant listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15 °C), 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 premix gas-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire gas using lean premix technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Lean premix gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Lean premix oil-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire oil using lean premix technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using lean premix technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Lean premix oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Lean premix technology means a configuration of a stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber.

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 this section, 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 this section, 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 this standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Municipal solid waste as used in this subpart is as defined in §60.1465 of Subpart AAAA of 40 CFR Part 60, New Source Performance Standards for Small Municipal Waste Combustion Units.

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. May be field or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field gas, refinery gas, and syngas.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Natural gas transmission and storage facility means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines. Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site (as defined in this section) and is connected by ancillary equipment, such as gas flow lines or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility.

North Slope of Alaska means the area north of the Arctic Circle (latitude 66.5 degrees North).

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 emission control device means an emission control device that incorporates catalytic oxidation to reduce CO emissions.

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.

Regenerative/recuperative cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to preheat the combustion air entering the combustion chamber of the stationary combustion turbine.

Research or laboratory facility means any stationary source whose primary purpose is to conduct research and development into new processes and products, where such source is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a *de minimis* matter.

Simple cycle stationary combustion turbine means any stationary combustion turbine that does not recover heat from the stationary combustion turbine exhaust gases.

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), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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.

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.

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006]

Table 1 to Subpart YYYY of Part 63—Emission Limitations

As stated in §63.6100, you must comply with the following emission limitations

For each new or reconstructed stationary combustion turbine described in §63.6100 which is . . .	You must meet the following emission limitations . . .
1. a lean premix gas-fired stationary combustion	limit the concentration of formaldehyde to

turbine as defined in this subpart, 2. a lean premix oil-fired stationary combustion turbine as defined in this subpart, 3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or 4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart.	91 ppbvd or less at 15 percent O_2.

Table 2 to Subpart YYYY of Part 63—Operating Limitations

As stated in §§63.6100 and 63.6140, you must comply with the following operating limitations

For . . .	You must . . .
1. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst	maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
2. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst	maintain any operating limitations approved by the Administrator.

Table 3 to Subpart YYYY of Part 63—Requirements for Performance Tests and Initial Compliance Demonstrations

As stated in §63.6120, you must comply with the following requirements for performance tests and initial compliance demonstrations

You must . . .	Using . . .	According to the following requirements . . .
a. demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 by a performance test initially and on an annual basis AND	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348–03 provided that %R as determined in Annex A5 of ASTM D6348–03 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator	formaldehyde concentration must be corrected to 15 percent O_2, dry basis. Results of this test consist of the average of the three 1 hour runs. Test must be conducted within 10 percent of 100 percent load.
b. select the sampling port location and the number of traverse points AND	Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	if using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
c. determine the O_2concentration at the sampling port location	Method 3A or 3B of 40 CFR part 60, appendix A	measurements to determine O_2concentration must be made at the same time as the

AND		performance test.
d. determine the moisture content at the sampling port location for the purposes of correcting the formaldehyde concentration to a dry basis	Method 4 of 40 CFR part 60, appendix A or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03	measurements to determine moisture content must be made at the same time as the performance test.

Table 4 to Subpart YYYY of Part 63—Initial Compliance With Emission Limitations

As stated in §§63.6110 and 63.6130, you must comply with the following requirements to demonstrate initial compliance with emission limitations

For the . . .	You have demonstrated initial compliance if . . .
emission limitation for formaldehyde.	the average formaldehyde concentration meets the emission limitations specified in Table 1.

Table 5 to Subpart YYYY of Part 63—Continuous Compliance With Operating Limitations

As stated in §§63.6135 and 63.6140, you must comply with the following requirements to demonstrate continuing compliance with operating limitations:

For each stationary combustion turbine complying with the emission limitation for formaldehyde . . .	You must demonstrate continuous compliance by . . .
1. with an oxidation catalyst	continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
2. without the use of an oxidation catalyst	continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

Table 6 to Subpart YYYY of Part 63—Requirements for Reports

As stated in §63.6150, you must comply with the following requirements for reports

If you own or operate a . . .	you must . . .	According to the following requirements . . .
1. stationary combustion turbine which must comply with the formaldehyde emission limitation	report your compliance status	semiannually, according to the requirements of §63.6150.

2. stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis	report (1) 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, digester gas, or gasified MSW is equivalent to 10 percent or more of the gross heat input on an annual basis, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters	annually, according to the requirements in §63.6150.
3. a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source	report (1) the number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters	annually, according to the requirements in §63.6150.

Table 7 of Subpart YYYY of Part 63—Applicability of General Provisions to Subpart YYYY

You must comply with the applicable General Provisions requirements:

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.1	General applicability of the General Provisions	Yes	Additional terms defined in §63.6175.
§63.2	Definitions	Yes	Additional terms defined in §63.6175.
§63.3	Units and abbreviations	Yes	
§63.4	Prohibited activities	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	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	Yes	
§63.6(d)	[Reserved]		
§63.6(e)(1)	Operation and maintenance	Yes	
§63.6(e)(2)	[Reserved]		
§63.6(e)(3)	SSMP	Yes	
§63.6(f)(1)	Applicability of standards except during startup, shutdown, or malfunction (SSM)	Yes	
§63.6(f)(2)	Methods for determining compliance	Yes	
§63.6(f)(3)	Finding of compliance	Yes	
§63.6(g)(1)–(3)	Use of alternative standard	Yes	
§63.6(h)	Opacity and visible emission standards	No	Subpart YYYY 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 YYYY contains performance test dates at §63.6110.
§63.7(a)(3)	Section 114 authority	Yes	
§63.7(b)(1)	Notification of performance test	Yes	

§63.7(b)(2)	Notification of rescheduling	Yes	
§63.7(c)	Quality assurance/test plan	Yes	
§63.7(d)	Testing facilities	Yes	
§63.7(e)(1)	Conditions for conducting performance tests	Yes	
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart YYYY specifies test methods at §63.6120.
§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 YYYY contains specific requirements for monitoring at §63.6125.
§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	Yes	
§63.8(c)(1)(ii)	Parts for repair of CMS readily available	Yes	
§63.8(c)(1)(iii)	SSMP for CMS required	Yes	
§63.8(c)(2)–(3)	Monitoring system	Yes	

	installation		
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart YYYY does not require continuous opacity monitoring systems (COMS).
§63.8(c)(5)	COMS minimum procedures	No	
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart YYYY 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.
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	
§63.8(f)(6)	Alternative to relative accuracy test	Yes	
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6135 and 63.6140.
§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.
§63.9(c)	Request for compliance extension	Yes	
§63.9(d)	Notification of special compliance requirements for new sources	Yes	
§63.9(e)	Notification of performance test	Yes	
§63.9(f)	Notification of visible emissions/opacity test	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	
§63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for	Yes	If alternative is in use.

	alternative to relative accuracy test audit (RATA) is exceeded		
§63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
§63.9(i)	Adjustment of submittal deadlines	Yes	
§63.9(j)	Change in previous information	Yes	
§63.10(a)	Administrative provisions for recordkeeping and reporting	Yes	
§63.10(b)(1)	Record retention	Yes	
§63.10(b)(2)(i)–(iii)	Records related to SSM	Yes	
§63.10(b)(2)(iv)–(v)	Records related to actions during SSM	Yes	
§63.10(b)(2)(vi)–(xi)	CMS 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 CMS	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 YYYY does not contain opacity or VE standards.

§63.10(d)(4)	Progress reports	Yes	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No	Subpart YYYY does not require reporting of startup, shutdowns, or malfunctions.
§63.10(e)(1) and (2)(i)	Additional CMS reports	Yes	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYY does not require COMS.
§63.10(e)(3)	Excess emissions and parameter exceedances reports	Yes	
§63.10(e)(4)	Reporting COMS data	No	Subpart YYYY does not require COMS.
§63.10(f)	Waiver for recordkeeping and 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	

Browse Previous

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:	**Purdue University - West Lafayette**
Source Location:	**401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, IN 47907**
County:	**Tippecanoe**
SIC Code:	**8221**
Operation Permit No.:	**T 157-27313-00012**
Operation Permit Issuance Date:	**August 27, 2010**
PSD/Significant Source Modification No.:	**157-32230-00012**
Significant Permit Modification No.:	**157-32275-00012**
Permit Reviewer:	**Josiah Balogun**

On February 1, 2013, the Office of Air Quality (OAQ) had a notice published in the Journal & Courier in Lafayette, Indiana, stating that Purdue University - West Lafayette had applied for a Significant Modification to their Part 70 Operating Title V Permit issued on August 27, 2010 relating to updates in their permit. 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 February 20, 2013, IDEM, OAQ received comments from David R. Jordan of ERM. 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. 157-27313-00012 (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comment 1: Comments on Section A.3 of the permit.

A. Condition A.3(a) – The description for the CT/HRSG1 should be revised to read "… permitted in **2013**…" rather than 2012. This change should also be made to the description for CT/HRSG1 in Section D.1, in Section E.4 and in Section E.5.

B. Condition A.3(b) – The description for Boiler 2 after it is converted to natural gas should be revised to read "… permitted to burn natural gas in **2013**…" rather than 2012. This change should also be made to the description for Boiler 2 after conversion to natural gas in Section D.1 and in Section F.

C. Condition A.3 – There has been a minor design change that results in a slight increase in the heat input capacity of the duct burners for the CT/HRSG1 and a slight decrease in heat input capacity for Boiler 2 after conversion to natural gas. These changes result in a decrease in the overall net NOx emissions from 36.85 tons per year to 34.50 tons per year and an increase in the overall net CO emissions from 80.72 tons per year to 82.78 tons per year. The requested equipment description changes are reflected in the language below:

a. The heat input capacity for the duct burners for CT/HRSG1 has increased from 65.3 mmBtu/hr to 75 mmBtu/hr. The description contained in Condition A.3(a) should be changed to read "One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, …, and natural gas fired duct burners, with heat input capacity at ISO conditions, of ~~65.3~~ **75.0** MMBtu per hour (HHV), …." This change should also be made to the description for CT/HRSG1 in Section D.1, in Section E.4 and in Section E.5.

b. The heat input capacity for the duct burners for Boiler 2 has decreased from 325 mmBtu/hr to 315 mmBtu/hr. The description contained in Condition A.3(b) should be changed to read "One (1) natural gas fired boiler, identified as Boiler 2, …, with a maximum heat input capacity of ~~325~~ **315** MMBtu per hour, …" This change should also be made to the description for Boiler 2 in Section D.1 and in Section F.

Response 1: The source has made a design change that will increase the capacity of the Turbine and reduce the capacity of the boiler. These changes result in a decrease in the overall net NOx emissions from 36.85 tons per year to 34.50 tons per year and an increase in the overall net CO emissions from 80.72 tons per year to 82.78 tons per year. This design change will not affect the PSD Minor Limits 326 IAC 2-2. The affected sections have been updated in the permit and a new calculation has been added to the permit as an addendum to the Appendix A.

A.3 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) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in **2013** ~~2012~~, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of **75** ~~65.3~~ MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

....

After fuel Change to Natural Gas:

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in **2013** ~~2012~~, with a maximum heat input capacity of **315** ~~325~~ MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Comment 2: Conditions B.9(a)(i) and B.9(c) – The reference to "responsible official" should be updated to 326 IAC 2-7-1**(35)**

Response 2: The citation in Condition B.9- Certification has been updated in the permit accordingly.

B.9 Certification [326 IAC 2-7-4(f)] [326 IAC 2-7-6(1)] [326 IAC 2-7-5(3)(C)]

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

(i) it contains a certification by a "responsible official", as defined by 326 IAC 2-7-1 (**35** ~~34~~), and

(ii) ********

....

(c) A "responsible official" is defined at 326 IAC 2-7-1(**35** ~~34~~).

Comment 3: Condition D.1.5 – This condition relates to the retirement of Boiler 1 while Condition D.1.5.1 relates to the conversion of Boiler 2 to natural gas. Paragraph (b) under Condition D.1.5 reads "Within thirty (30) days, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 1 was decommissioned and the date when Boiler 2 was converted to use natural gas." Purdue suggests the following changes related to this condition:

a. Change the wording for Condition D.1.5(b) to read "Within thirty (30) days **after the date Boiler 1 is decommissioned**, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 1 was decommissioned ~~and the date when Boiler 2 was converted to use natural gas~~."

b. Change the current wording of Condition D.1.5.1 to be paragraph (a) and add a new paragraph (b) which reads "**Within thirty (30) days after the date Boiler 2 is converted to natural gas, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 2 was converted to use natural gas.**"

Response 3: Conditions D.1.5 - Retirement of Existing Operations and D.1.5.1 - Retirement of Existing Operations have been revised in the permit for clarification purposes.

D.1.5 Retirement of Existing Operations [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2, the Permittee shall permanently discontinue the operation of Boiler 1 within one hundred eighty (180) days of the startup date for Boiler 7. NO_X emissions from Boiler 7 shall not exceed 40 tons during this period.

(b) Within thirty (30) days **after the date Boiler 1 is decommissioned**, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 1 was decommissioned ~~and the date when Boiler 2 was converted to use natural gas~~.

D.1.5.1 Retirement of Existing Operations [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2, after the conversion of Boiler 2 to natural gas, the Permittee shall immediately discontinue the use of coal in the spreader stoker coal fired boiler.

(b) **Within thirty (30) days after the date Boiler 2 is converted to natural gas, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 2 was converted to use natural gas.**

Comment 4: Condition D.1.15 – This condition relates to parametric monitoring for the baghouse control system for Boiler 2 while burning coal. The first sentence of paragraph (c) should be removed as this sentence references Boiler 1, which does not have a baghouse control system.

Response 4: The typo in Condition D.1.15 - Baghouse Parametric Monitoring has been corrected in the Permit accordingly

D.1.15 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

....

(c) ~~Condition D.1.15 – Baghouse Parametric Monitoring, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned.~~ Condition D.1.15 – Baghouse Parametric Monitoring, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

Comment 5: Condition D.4.4 – The reference to Condition D.4.4 in subsections (b) and (c) should be changed to reference Condition D.4.3.

Response 5: The typo in Condition D.4.4 - Record Keeping Requirement has been corrected in the Permit accordingly.

D.4.4 Record Keeping Requirements

....

(b) To document the compliance status with Condition **D.4.3** ~~D.4.4~~ - 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.

(c) In the event that a breakdown of the NOx continuous emission monitoring system (CEMS) occurs in Condition **D.4.3** ~~D.4.4~~ - 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.

....

Comment 6: In addition to the comments provided above, Purdue would like to clarify information provided in the transmittal letter from IDEM to Purdue dated January 29, 2013 and signed by Len Pogost with the Permits Branch of the Office of Air Quality. This letter indicates that OAQ has placed a copy of the draft permit package in the Clinton Public Library in Clinton, Indiana, and that Purdue is obligated to place a copy of the permit application at this library. Purdue assumes that this statement should reference the West Lafayette Public Library, in West Lafayette, Indiana as the location of the draft permit package, as this is the location noted in the public notice and in all other documents related to this permit. Purdue has provided a copy of the permit application for this permit to the West Lafayette Public Library as indicated in its application.

Response 6: The statement "This letter indicates that OAQ has placed a copy of the draft permit package in the Clinton Public Library in Clinton, Indiana, and that Purdue is obligated to place a copy of the permit application at this library" is a typo. The correct reference is West Lafayette Public Library, in West Lafayette. The source has provided a copy of the permit application for this permit to the West Lafayette Public Library as indicated in its application. The copy of the permit package shall be placed at the West Lafayette Public Library, in West Lafayette, Indiana after the issuance of this permit for clarification purposes.

Other Changes

Upon further review IDEM, OAQ has made the following changes to the Title V permit T157-27313-00012. (deleted language appears as ~~strikout~~ and the new language **bolded**):

Change 1: 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.

TSD:

326 IAC 6-2-4 (Particulate Emissions Limitations for Source of Indirect Heating)
Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the boiler, identified as Boiler 2 and the natural gas-fired combustion turbine/heat recovery steam generator, identified as CT/HRSG1 shall not exceed ~~0.167~~ **0.168** pounds per million Btu heat input (lb/MMBtu), each. This limitation was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}} = \cancel{0.167}\ \mathbf{0.168}\ \text{lbs/MMBtu}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
~~For this unit, Q = (286+279+290+10+2+325+138.2) = 1330.2 MMBtu/hr.~~
For this unit, Q = (286+279+290+10+2+315+159.2) = 1341.2 MMBtu/hr.

Permit:

D.1.2.1 Particulate Emission Limitations for Sources of Indrirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the boiler, identified as Boiler 2 and the natural gas-fired combustion turbine/heat recovery steam generator, identified as CT/HRSG1 shall not exceed ~~0.167~~ **0.168** pounds per million Btu heat input (lb/MMBtu), each.

Note: The PM emissions limit for Boiler 2 shall become effective after Boiler 2 is converted to natural gas.”

Change 2: IDEM acknowledges the above facts by the ATSD. 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 The Permit Level determination table has been revised due to an increase in the Turbine design and a decrease in the boiler design. The increase and decrease are reflected in the tables below.

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.

	Potential to Emit (Tons per year)												
Process	PM (tons)	PM_{10} (Tons)	$PM_{2.5}$ (tons)	SO_2	VOC	NOx	CO	GHGs as CO2e	Lead	Be	Hg	He	Total HAPs
Boiler 7 (NG)	9.46	9.46	9.46	0.75	6.85	62.26	104.6	145,717.3	6.23E-04	1.49E-05	3.24E-04	2.24	2.35
New CT/HRSG	~~36.35~~ **40.59**	~~36.35~~ **40.59**	~~36.35~~ **40.59**	0.1	~~5.04~~ **5.37**	~~61.79~~ **66.04**	~~69.10~~ **73.34**	~~79,547.3~~ **81,513.90**	---	---	---	---	--
Boiler 2 (NG)	~~10.6~~ **10.28**	~~10.6~~ **10.28**	~~10.6~~ **10.28**	~~0.84~~ **0.81**	~~7.68~~ **7.44**	~~213.5~~ **206.9**	~~71.18~~ **68.99**	~~163,303.9~~ **158,279.18**	~~6.98E-04~~ **6.76E-04**	~~1.67E-05~~ **1.62E-05**	~~3.63E-04~~ **3.52E-04**	~~2.51~~ **2.43**	~~2.63~~ **2.55**
Total Emissions	~~56.4~~ **60.34**	~~56.4~~ **60.34**	~~56.4~~ **60.34**	~~1.68~~ **1.66**	~~19.57~~ **19.66**	~~337.6~~ **335.3**	~~245~~ **246.9**	~~385,568.55~~ **385,510.43**	~~0.0012~~ **0.00**	0.00003	~~0.0006~~ **0.00**	~~4.75~~ **4.68**	~~4.98~~ **4.90**
PSD Significant Level	25	15	10	40	40	40	100	75,000	0.6	0.0004	0.1	NA	NA

Since PM, PM10, PM2.5, NOx, and CO are emitted in significant levels from the proposed modification, 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.
SO2, VOC, lead, Beryllium, and Hexane are not emitted at significant level from the proposed modification. Therefore, netting was not triggered for these pollutants.

	Netting Analysis (ton/year)										
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**VOC**	**NOx**	**CO**	**GHGs as CO2e**	**Lead**	**Beryllium (Be)**	**Mercury (Hg)**
Boiler 7 (NG)	9.46	9.46	9.46	0.75	6.85	62.26	104.6	145,717.3	6.23E-04	1.49E-05	3.24E-04
New CT/HRSG	~~36.35~~ **40.59**	~~36.35~~ **40.59**	~~36.35~~ **40.59**	0.1	~~5.04~~ **5.37**	~~61.79~~ **66.04**	~~69.10~~ **73.34**	~~79,547.3~~ **81,513.90**	---	---	---
Boiler 2 (NG)	~~10.6~~ **10.28**	~~10.6~~ **10.28**	~~10.6~~ **10.28**	~~0.84~~ **0.81**	~~7.68~~ **7.44**	~~213.5~~ **206.9**	~~71.18~~ **68.99**	~~163,303.9~~ **158,279.18**	~~6.98E-04~~ **6.76E-04**	~~1.67E-05~~ **1.62E-05**	~~3.63E-04~~ **3.52E-04**
Contemp. Nat Gas Em. Gens	0.0019	0.0019	0.0019	0.00013	0.0227	0.784	0.107	22.05	0	0	0
Contemp. Nat Gas Boiler	0.2887	0.2887	0.2887	0.0228	0.2089	3.7986	3.1908	4,445	1.9E-05	4.56E-07	9.8E-06
Contemp. Diesel Em Gen < 600hp	3.17	3.17	3.17	2.96	3.56	44.7	9.63	1658.3	0	0	0
Contemp. Diesel Em Gen > 600hp	0.07	0.06	0.06	0.54	0.01	3.42	173.9	173.9	0	0	0
Contemp. Poultry Incinerator	0.13	0.15	0.15	1.22	0.05	0.8	0.09	284.7	0	0	0
Contemporaneous Increase	~~56.4~~ **60.3**	~~56.4~~ **60.3**	~~56.4~~ **60.3**	~~1.68~~ **1.69**	~~19.57~~ **19.66**	~~337.6~~ **387.96**	~~245~~ **246.93**	~~385,568.55~~ **385,510.9**	0.00	0.00	0.00
Contemporaneous Decrease (Boiler 1 Removal)	420.11	306.10	190.50	1390.19	1.525	353.44	164.15	152,567	0.00735	0	0.00215
Total for Modification after Netting	~~-363.69~~ **-359.77**	~~-249.7~~ **-245.8**	~~-134.1~~ **-130.2**	-1,388.5	~~18.0~~ **18.13**	~~36.85~~ **34.52**	~~80.8~~ **82.78**	~~233,002~~ **232,943.9**	-0.01	~~0.00002~~ **0.00**	~~0.00003~~ **0.00**
Total for Modification	0	0	0	0	~~18.0~~ **18.13**	~~36.85~~ **34.52**	~~80.8~~ **82.78**	~~233,002~~ **232,943.9**	0	~~0.00002~~ **0.00**	~~0.00003~~ **0.00**
Significant Level	25	15	10	40	40	100	40	75,000 CO_2e	0.6	0.0004	0.1

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:	**Purdue University - West Lafayette**
Source Location:	**401 S. Grant St., Freehafer Hall of Administrative Services, West Lafayette, IN 47907**
County:	**Tippecanoe**
SIC Code:	**8221**
Operation Permit No.:	**T 157-27313-00012**
Operation Permit Issuance Date:	**August 27, 2010**
PSD/Significant Source Modification No.:	**157-32230-00012**
Significant Permit Modification No.:	**157-32275-00012**
Permit Reviewer:	**Josiah Balogun**

Source Definition

This source consists of air emission units located on the main campus in West Lafayette, Indiana, and at research farms in the vicinity of 5675 West 600 North, West Lafayette, Indiana, for the Animal Sciences Research and Education Center.

Existing Approvals

The source was issued Part 70 Operating Permit No. 157-27313-00012 on August 27, 2010. The source has since received the following approvals:

(a) Significant Source Modification No. 157-27361-00012, issued on July 9, 2010;

(b) Administrative Amendment No. 157-30222-00012, issued on March 2, 2011.

(c) Revocation No. 157-30359-00012, issued on March 21, 2011.

(d) Administrative Amendment No. 157-30374-00012, issued on April 19, 2011; and

(e) Significant Permit Modification No. 157-30742-00012, issued on May 1, 2012.

County Attainment Status

The source is located in Tippecanoe County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective April 5, 2005, for 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. Tippecanoe 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) $PM_{2.5}$
Tippecanoe County has been classified as attainment for $PM_{2.5}$. On May 8, 2008 U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011 the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, June 28, 2011. Therefore, direct $PM_{2.5}$ 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
Tippecanoe 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 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

Pollutant	**Emissions** (ton/yr)
GHGs as CO_2e	> 100, 000
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, emissions of GHGs are equal to or greater than one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year 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 Significant Permit Modification 157-30742-00012, issued on May 1, 2012.

(c) This existing source is a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Purdue University - West Lafayette on September 4, 2012, relating to certain improvements to Purdue's Wade Utility Plant approved by the Board of Trustee. The improvements are the construction of a new combustion turbine with a heat recovery steam generator (CT/HRSG) and the conversion of Boiler 2 from coal to natural gas. The conversion of Boiler 2 to natural gas will have no impact on Purdue's energy production (since there is no change in capacity of Boiler 2 as a result of this project), however it will play an important role in Purdue's ability to meet Maximum Achievable Control Technology (MACT) standards for operations at the Wade Utility Plant. The following is a list of the proposed emission unit(s) and pollution control device(s):

(a) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2012, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 65.3 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

<u>After fuel Change to Natural Gas:</u>

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in 2012, with a maximum heat input capacity of 325 MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

NOTE: In January 2009, Purdue submitted an application to construct two new boilers and retire existing Boiler 1 at its Wade Utility Plant. The proposed new units were a new circulating fluidized bed coal-fired boiler designated as Boiler 6 with a heat input of 380 MMBtu/hr and a new natural gas-fired boiler designated as Boiler 7 with a heat input of 290 MMBtu/hr. Due to the emission reductions that would occur as a result of discontinuing the operation of Boiler 1, the net emissions increase as a result of the addition of Boiler 6 and Boiler 7 did not trigger major new source review under Prevention of Significant Deterioration (PSD) rules. The Significant Source Modification permit allowing the construction of Boiler 6 and Boiler 7 was approved by IDEM on July 9, 2010.

Although Boiler 6 and Boiler 7 were both approved for construction by IDEM, the Purdue Board of Trustees made the decision to abandon the Boiler 6 portion of the project in February 2011. All permit conditions related to Boiler 6 have now been removed from Purdue's Title V operating permit. Purdue has proceeded with the construction of Boiler 7 and, as specified in its Title V permit, will remove Boiler 1 from service within 180 days of the date that Boiler 7 starts up.

Enforcement Issues

There are no pending enforcement actions.

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	56.42
PM_{10}	56.42
$PM_{2.5}$	56.42
SO_2	1.68
VOC	19.57
CO	244.87
NO_X	337.58
CO2e	385,568.55

This source modification is subject to 326 IAC 2-7-10.5(g)(4) and (7) because potential to emit PM, PM_{10} and NO_X are greater than 25 tons per year, potential to emit CO is greater than 100 tons per year. 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)(1), because the modification requires significant changes to the existing Part 70 permit terms and conditions.

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.

	Potential to Emit (Tons per year)												
Process	PM (tons)	PM_{10} (Tons)	$PM_{2.5}$ (tons)	SO_2	VOC	NOx	CO	GHGs as CO2e	Lead	Be	Hg	He	Total HAPs
Boiler 7 (NG)	9.46	9.46	9.46	0.75	6.85	62.26	104.6	145,717.3	6.23E-04	1.49E-05	3.24E-04	2.24	2.35
New CT/HRSG	36.35	36.35	36.35	0.1	5.04	61.79	69.10	79,547.3	---	---	---	---	--
Boiler 2 (NG)	10.6	10.6	10.6	0.84	7.68	213.5	71.18	163,303.9	6.98E-04	1.67E-05	3.63E-04	2.51	2.63
Total Emissions	56.4	56.4	56.4	1.68	19.57	337.6	245	385,568.55	0.0012	0.00003	0.0006	4.75	4.98
PSD Significant Level	25	15	10	40	40	40	100	75,000	0.6	0.0004	0.1	NA	NA

Since PM, PM10, PM2.5, NOx, and CO are emitted in significant levels from the proposed modification, 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.

SO2, VOC, lead, Beryllium, and Hexane are not emitted at significant level from the proposed modification. Therefore, netting was not triggered for these pollutants.

	Netting Analysis (ton/year)										
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**VOC**	**NOx**	**CO**	**GHGs as CO2e**	**Lead**	**Beryllium (Be)**	**Mercury (Hg)**
Boiler 7 (NG)	9.46	9.46	9.46	0.75	6.85	62.26	104.6	145,717.3	6.23E-04	1.49E-05	3.24E-04
New CT/HRSG	36.35	36.35	36.35	0.1	5.04	61.79	69.10	79,547.3	---	---	---
Boiler 2 (NG)	10.6	10.6	10.6	0.84	7.68	213.5	71.18	163,303.9	6.98E-04	1.67E-05	3.63E-04
Contemp. Nat Gas Em. Gens	0.0019	0.0019	0.0019	0.00013	0.0227	0.784	0.107	22.05	0	0	0
Contemp. Nat Gas Boiler	0.2887	0.2887	0.2887	0.0228	0.2089	3.7986	3.1908	4,445	1.9E-05	4.56E-07	9.8E-06
Contemp. Diesel Em Gen < 600hp	3.17	3.17	3.17	2.96	3.56	44.7	9.63	1658.3	0	0	0
Contemp. Diesel Em Gen > 600hp	0.07	0.06	0.06	0.54	0.01	3.42	173.9	173.9	0	0	0
Contemp. Poultry Incinerator	0.13	0.15	0.15	1.22	0.05	0.8	0.09	284.7	0	0	0
Contemporaneous Increase	56.4	56.4	56.4	1.68	19.57	337.6	245	385,568.55	0.00	0.00	0.00
Contemporaneous Decrease (Boiler 1 Removal)	420.11	306.10	190.50	1390.19	1.525	353.44	164.15	152,567	0.00735	0	0.00215
Total for Modification after Netting	-363.69	-249.7	-134.1	-1,388.5	18.0	36.85	80.8	233,002	-0.01	0.00002	0.00003
Total for Modification	0	0	0	0	18.0	36.85	80.8	233,002	0	0.00002	0.00003
Significant Level	25	15	10	40	40	100	40	75,000 CO_2e	0.6	0.0004	0.1

In January 2009, Purdue submitted an application to construct two new boilers and retire existing Boiler 1 at its Wade Utility Plant. The proposed new units were a new circulating fluidized bed coal-fired boiler designated as Boiler 6 with a heat input of 380 MMBtu/hr and a new natural gas-fired boiler designated as Boiler 7 with a heat input of 290 MMBtu/hr. Due to the emission reductions that would occur as a result of discontinuing the operation of Boiler 1, the net emissions increase as a result of the addition of Boiler 6 and Boiler 7 did not trigger major new source review under Prevention of Significant Deterioration (PSD) rules. The Significant Source Modification permit allowing the construction of Boiler 6 and Boiler 7 was approved by IDEM on July 9, 2010.

The applicant aggregated the 2009 and 2012 modification together and the netting analysis is done to ensure that both phases of the modifications are less than PSD significant levels. The netting analysis done during this modification is a continuation of the netting analysis that was done for the 2009 Modification and it was concluded that, there will be no increase in emissions from these modifications except for the CO2e emissions in the 2012 modification. The 2012 modification makes the source a major source of CO2e, at the time IDEM permitted the 2009 modification, CO2e was not a regulated pollutant. Pursuant to 326 IAC 2-2-2(g), the source is exempt from certain requirements of 326 IAC 2-2, including Best Available Control Techonology Analysis (BACT), pre-construction ambient air quality monitoring, and additional impact analysis because the source is a non-profit educational institution. Therefore, the requirements of 326 IAC 2-2-3 (PSD) are not applicable to this modification

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.

Pursuant to 40 CFR 64.2(b)(1)(vi), the requirements of 40 CFR Part 64 (CAM) shall not apply to emission limitations or standards for which a Part 70 permit specifies a continuous compliance determination method. Since compliance with the NOx emission limitations in the Part 70 permit is specified to be determined by continuous emissions monitoring systems (CEMS), therefore, CAM is not applicable to CT/HRSG1 and Boiler 2 for NOx emissions. All other emission units have uncontrolled emissions less than the major source threshold.

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

(b) The requirements of the New Source Performance Standard, 40 CFR 60, Subpart Db, Standard of Performance for Industrial -Commercial-Institutional Steam Generating Units, which is incorporated by reference as 326 IAC 12, applies to each steam generating unit with a heat input capacity greater than 100 MMBtu/hr unless the unit meets any of the exemptions identified in 40 CFR 60.40Db. Per 40 CFR 60.40Db(i), HRSGs that are associated with combined cycle gas turbines and that meet the applicability requirements of NSPS KKKK are not subject to NSPS Subpart Db. The proposed duct burner has a heat input capacity less than 100 MMBtu/hr. Therefore, the proposed duct burner is not subject to the requirements of NSPS Db.

(c) The proposed boiler, identified as Boiler 2 is not subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart Db, Standard of Performance for

Industrial -Commercial Institutional Steam Generating Unit, which is incorporated by reference as 326 IAC 12 because the boiler does not qualifies as a modification or as reconstruction as defined under NSPS 40 CFR 60.14. Pursuant to 40 CFR 60.15 this modification does not qualifies as a reconstruction also because the project involves the installation of natural gas burners on Boiler 2, the removal of equipment associated with coal combustion, the addition of flue gas recirculation, and the cost to bypass the current baghouse. The total cost for this project is currently estimated as $2,500,000. Purdue estimates that the cost to construct a new coal-fired spreader stoker of this size would be more than $55,000,000. The fixed capital cost of the new components will not exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Based on this information, it is reasonable to conclude that the proposed conversion of Boiler 2 to natural gas would not be classified as reconstruction under NSPS. Therefore the boiler is not subject to the requirements of 40 CFR 60 Subpart Db.

(d) The requirements of the New Source Performance Standard of Performance for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK applies to combustion turbine 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 Purdue have peak heat inputs greater than 10 MMBtu/hr. Therefore, the combustion turbine, HRSG, and duct burner are subject to the requirements of 40 CFR 60, Subpart KKKK.

These emission units are subject to the following portions of Subpart KKKK:

(1) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2012, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 65.3 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

The combustion turbine, HRSG and duct burner 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
20. Table 1

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

(e) The requirements of National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY establishes emission and operating limitations for HAP emitted from stationary combustion turbine located at major sources of HAP emissions. The Combustion turbine at Purdue will be subject to this rule because the emission unit is located in a major source of HAP.

These emission units are subject to the following portions of Subpart YYYY:

(1) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2012, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 65.3 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

The combustion turbine, HRSG and duct burner are subject to the following Sections of 40 CFR Part 63, Subpart YYYY.

1. 40 CFR 63.6080
2. 40 CFR 63.6085
3. 40 CFR 63.6090
4. 40 CFR 63.6092
5. 40 CFR 63.6095
6. 40 CFR 63.6100
7. 40 CFR 63.6105
8. 40 CFR 63.6110
9. 40 CFR 63.6115
10. 40 CFR 63.6120
11. 40 CFR 63.6125
12. 40 CFR 63.6130
13. 40 CFR 63.6135
14. 40 CFR 63.6140
15. 40 CFR 63.6150
16. 40 CFR 63.6155
17. 40 CFR 63.6160
18. 40 CFR 63.6165
19. 40 CFR 63.6170
20. 40 CFR 63.6175
21. Table 1 to Subpart YYYY of Part 63
22. Table 2 to Subpart YYYY of Part 63
23. Table 3 to Subpart YYYY of Part 63
24. Table 4 to Subpart YYYY of Part 63
25. Table 5 to Subpart YYYY of Part 63
26. Table 6 to Subpart YYYY of Part 63
27. Table 7 to Subpart YYYY of Part 63

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 63 Subpart YYYY.

(f) Boiler 2 would have been subject to 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. However, on June 8, 2007, the United States Court of appeals for the District of Columbia Circuit (in NRDC v. EPA, no. 04-1386) vacated in its entirety the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD. Additionally, since the state rule at 326 IAC 20-95 incorporated the requirements of the NESHAP 40 CFR 63, Subpart DDDDD by reference, the requirements of 326 IAC 20-95 are no longer effective. Therefore, the requirements of 40 CFR 63, Subpart DDDDD and 326 IAC 20-95 are not included in the permit.

State Rule Applicability Determination

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))
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 net emission increase from this modification is greater than 100 tons per year for CO emissions. In order to make the requirements of 326 IAC 2-2 (PSD) not applicable to the 2012 modification, the Permittee has taken the following limits:

(a) The uncontrolled CO emissions for Boiler 2 is greater than 100 tons per year for this modification. The natural gas usage of the boiler, identified as Boiler 2 shall be less than 2,791 million cubic feet per twelve (12) consecutive month period, with compliance determined at the end of each month, and the CO emissions shall not exceed 51 pounds per million cubic feet of natural gas.

Compliance with these limits, with the net contemporaneous increases from the new emission units and the net contemporaneous decreases from the Boiler 1 (2009 Modification) will ensure that the CO emissions from the Boiler, identified as Boiler 2 is less than 100 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2009/2012 modification.

(b) The uncontrolled NOx emissions for CT/HRSG1 and the duct burner are greater than 40 tons per year for this modification. The combined NOx emissions from the natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 and the duct burner shall not exceed 14.1 pounds per hour. Compliance with this limit, with the net contemporaneous increases from the new emission units and the net contemporaneous decreases from the Boiler 1 (2009 Modification) will ensure that the NOx emissions from the natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 and the duct burner is less than 40 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2009/2012 modification.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of boiler, identified as Boiler 2 and the natural gas-fired combustion turbine/heat recovery steam generator, identified as CT/HRSG1 will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 6-2-4 (Particulate Emissions Limitations for Source of Indirect Heating)
Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the boiler, identified as Boiler 2 and the natural gas-fired combustion turbine/heat recovery steam generator,

identified as CT/HRSG1 shall not exceed 0.167 pounds per million Btu heat input (lb/MMBtu), each. This limitation was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}} = 0.167 \text{ lbs/MMBtu}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
For this unit, Q = (286+279+290+10+2+325+138.2) = 1330.2 MMBtu/hr.

326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations)

(a) The boiler, identified as Boiler 2 is not subject to 326 IAC 326 IAC 7-1.1 because its SO_2 PTE (or limited SO_2 PTE) is less than 25 tons per year or 10 pounds/hour.

(a) The natural gas-fired combustion turbine/heat recovery steam generator, identified as CT/HRSG1 is not subject to 326 IAC 326 IAC 7-1.1 because its SO_2 PTE (or limited SO_2 PTE) is less than 25 tons per year or 10 pounds/hour.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)

(a) The uncontrolled VOC emissions from the boiler, identified as Boiler 2 is less than 25 tons per year. Therefore, the requirements of 326 IAC 8-1-6 (New Facilities; General Reduction Requirements) do not apply to this emission unit for this modification.

(b) The uncontrolled VOC emissions from the natural gas-fired combustion turbine/heat recovery steam generator, identified as CT/HRSG1 is less than 25 tons per year. Therefore, the requirements of 326 IAC 8-1-6 (New Facilities; General Reduction Requirements) do not apply to this emission unit for this modification.

326 IAC 24 Clean Air Interstate Rule (CAIR)

(a) The natural gas-fired combustion turbine/heat recovery steam generator, identified as units CT/HRSG is not subject to the 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) because the CT/HRSG does not have heat input above 250 mmBtu/hr, therefore, it is not a large affected unit.

(b) The boiler, identified as Boiler 2, is subject to the 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).

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.

Testing Requirements

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
Boiler 2	No Control	60 days / no later than 180 days	CO	One time testing	326 IAC 2-2

Note: Compliance with the NOx emission for the combustion turbine and the boiler are demonstrated by using the NOx CEMs data.

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. 157-27313-00012. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Change 1: The new combustion turbine and the boiler, identified as Boiler 2 that was converted to natural gas have been added to the Section A.3 of the permit accordingly.

A.3 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) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2012, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 65.3 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

<u>After the startup of Boiler 7 this boiler, identified as Boiler 1 shall be decommissioned within one hundred and eighty (180) days:</u>

(a1) One (1) spreader stoker coal fired boiler, identified as Boiler 1, with installation completed in 1960, with a nominal capacity of 281 MMBtu/hr, with a multi-cyclone collector and an electrostatic precipitator for particulate matter control, exhausting to stack WADE 01. Boiler 1 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After the fuel change from coal to natural gas in Boiler 2, the coal usage shall be discontinued in this boiler, identified as Boiler 2:

(b1) One (1) spreader stoker coal fired boiler, identified as Boiler 2, with installation completed in 1967, with a nominal capacity of 274 MMBtu/hr, with a multi-cyclone collector and a multi-compartment baghouse for particulate matter control, exhausting to stack WADE 02. Boiler 2 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After fuel Change to Natural Gas:

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in 2012, with a maximum heat input capacity of 325 MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

....

Change 2: The emission unit description box in Section D.1 has been updated with the new emission unit, natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 and the natural gas fired boiler, identified as Boiler 2 that was converted from coal to natural gas. All associated conditions have been added to Section D.1.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

~~**FACILITY OPERATION CONDITIONS**~~

~~**Facility**~~ **Emission Unit Description [326 IAC 2-7-5(15)]:**

(a) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2012, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 65.3 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.

<u>After the startup of Boiler 7 this boiler, identified as Boiler 1 shall be decommissioned within one hundred and eighty (180) days:</u>

(a1) One (1) spreader stoker coal fired boiler, identified as Boiler 1, with installation completed in 1960, with a nominal capacity of 281 MMBtu/hr, with a multi-cyclone collector and an electrostatic precipitator for particulate matter control, exhausting to stack WADE 01. Boiler 1 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

<u>After the fuel change from coal to natural gas in Boiler 2, the coal usage shall be discontinued in this boiler, identified as Boiler 2:</u>

(b1) One (1) spreader stoker coal fired boiler, identified as Boiler 2, with installation completed in 1967, with a nominal capacity of 274 MMBtu/hr, with a multi-cyclone collector and a multi-compartment baghouse for particulate matter control, exhausting to stack WADE 02. Boiler 2 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

<u>After fuel Change to Natural Gas:</u>

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in 2012, with a maximum heat input capacity of 325 MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

(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.1.1 Nitrogen Oxides Emission Limitation [326 IAC 2-2-4]

In order to make the requirements of 326 IAC 2-2 (PSD Requirements) not applicable to the addition of natural gas fired burners to the existing Boilers 1 and 2, the following limits shall apply:

(a) The combined natural gas usage for Boiler 1 and Boiler 2 shall not exceed 395 million cubic feet (MMCF) per twelve (12) consecutive month period. Compliance with this limit shall be determined at the end of each month.

(b) NO_X emissions from the Boiler 1 and Boiler 2 natural gas fired burners shall not exceed 200 pounds per million cubic feet (lb/MMCF) of natural gas.

Note: These limits shall cease for Boiler 1 after Boiler 1 is decommissioned. These Limits shall cease for Boiler 2 after Boiler 2 is converted to Natural Gas."

D.1.1.1 Prevention of Significant Deterioration (PSD) Minor Limit [326 IAC 2-2]

(a) The CO emissions from the Boiler identified as Boiler 2 shall be limited as follows:

(1) The natural gas usage of the boiler, identified as Boiler 2 shall be less than 2,791 million cubic feet per twelve (12) consecutive month period, with compliance determined at the end of each month.

(2) The CO emissions shall not exceed 51 pounds per million cubic feet of natural gas.

Compliance with these limits, with the net contemporaneous increases from the new emission units and the net contemporaneous decreases from the Boiler 1 (2009 Modification) will ensure that the CO emissions from the Boiler, identified as Boiler 2 is less than 100 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2009/2012 modification.

(b) The combined NOx emissions from the natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 and the duct burner shall not exceed 14.1 pounds per hour on a 30-day rolling basis. Compliance with this limit, with the net contemporaneous increases from the new emission units and the net contemporaneous decreases from the Boiler 1 (2009 Modification) will ensure that the NOx emissions from the natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 and the duct burner in combination with other contemporaneous increases and decreases is less than 40 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2009/2012 modification.

D.1.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

(a) Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating), particulate matter (PM) emissions from Boiler 1 and Boiler 2 shall not exceed 0.64 pound per million British thermal units (lb/MMBtu) of heat input. ~~, based on the following equation:~~

$$\cancel{Pt = \frac{(C)(a)(h)}{76.5\,(Q^{0.75})\,(N^{0.25})}}$$

~~Where: C = 50 micrograms per cubic meter (µ/m³)~~
~~Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu) heat input.~~
~~Q = Total source maximum operating capacity rating in million British thermal units per hour (MMBtu/hr) heat input.~~
~~N = Number of stacks in fuel burning operation.~~
~~a = 0.67~~
~~h = Stack height in feet.~~

~~For Boiler 1 and Boiler 2, Q = 555 MMBtu/hr, N = 2, and h = 200 feet.~~

(b) Condition D.1.2 - Particulate Emission Limitations for Sources of Indirect Heating, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.2 – Particulate Emission Limits for Sources of Indirect Heating, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas."

D.1.2.1 Particulate Emission Limitations for Sources of Indrirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the boiler, identified as Boiler 2 and the natural gas-fired combustion turbine/heat recovery steam generator, identified as CT/HRSG1 shall not exceed 0.167 pounds per million Btu heat input (lb/MMBtu), each.

Note: The PM emissions limit for Boiler 2 shall become effective after Boiler 2 is converted to natural gas."

D.1.3 SO_2 PSD Emission Limit [326 IAC 2-2-4]

(a) Pursuant to Construction Permit PC (79) 1680, issued June 6, 1988, 326 IAC 2-2 (Prevention of Significant Deterioration), and 326 IAC 7-1.1-2, the following conditions became effective upon start-up of Boiler 5:

(1) Sulfur dioxide emissions from Boiler 1 and Boiler 2 shall be limited to 5.43 pounds per million British thermal units (lb/MMBtu) of heat input and to a total of 26.5 tons from Boiler 1 and Boiler 2 on any calendar day.

(2) The 24-hour emission limit for sulfur dioxide shall be calculated by using the sulfur content of the coal as presently reported to the OAQ in accordance with 326 IAC 3-7-2 or 3-7-3. The daily coal usage will be calculated by the use of steam production data and an evaporation factor (pounds of steam per pounds of coal). The evaporation factor shall be 8.4 pounds of steam per pound of coal. Purdue University may request a permit modification to adjust this factor if performance data warrants a review.

(b) When the daily coal usage is 420 tons or less for Boiler 1 and Boiler 2, a daily sulfur dioxide emissions level need not be provided.

(c) The stack height on the existing boilers may be increased to 65 meters without obtaining approval from the IDEM, OAQ.

(d) The Permittee may at any time submit further modeling data in an effort to demonstrate that a higher 24-hour sulfur dioxide emission level from Boiler 1 and Boiler 2 will protect the sulfur dioxide air quality standards using procedures acceptable to the OAQ. The OAQ, after appropriate review, may adjust the 24-hour sulfur dioxide limit if the air quality analysis supports an adjusted level.

(e) Condition D.1.3 – SO_2 PSD Emission Limit, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.3 – SO_2 PSD Emission Limit, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas."

D.1.4 Sulfur Dioxide Emission Limitations (SO_2) [326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from Boiler 1 and Boiler 2 shall not exceed six and zero-tenths (6.0) pound per million British thermal units (lb/MMBtu), using a calendar month average.

(b) Condition D.1.4 – Sulfur Dioxide Emission Limitations (SO_2), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.4 – Sulfur Dioxide Emission Limitations (SO_2), shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.5 Retirement of Existing Operations [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2, the Permittee shall permanently discontinue the operation of Boiler 1 within one hundred eighty (180) days of the startup date for Boiler 7. NO_X emissions from Boiler 7 shall not exceed 40 tons during this period.

(b) Within thirty (30) days, the Permittee shall provide a notification to IDEM indicating the date on which Boiler 1 was decommissioned and the date when Boiler 2 was converted to use natural gas.

D.1.5.1 Retirement of Existing Operations [326 IAC 2-2]

Pursuant to 326 IAC 2-2, after the conversion of Boiler 2 to natural gas, the Permittee shall immediately discontinue the use of coal in the spreader stoker coal fired boiler.

D.1.6 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, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limitation established by 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)]
Operation of the emission control devices is not required during these times unless necessary to comply with these limits.

(2) 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 and stated in Section C - Opacity. 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 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.

(c) Condition D.1.6 – Temporary Alternative Opacity Limitations, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.6 – Temporary Alternative Opacity Limitations, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.7 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for Boiler 1 and Boiler 2 and their emission control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.1.8 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) Compliance with the PM limitation for Boiler 1 and Boiler 2 shall be determined by performance stack tests conducted using methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following 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 obligations with regard to the performance testing required by this condition.

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

(b) In order to demonstrate compliance with Condition D.1.1.1(a) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after Boiler 2 is converted to natural gas, the Permittee shall conduct CO emissions stack testing of the emissions from stack WADE 2 utilizing methods as approved by the commissioner. This testing shall be done once to demonstrate compliance with the CO limit. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(c) Condition D.1.8(a) – Testing Requirements, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.8(a) – Testing Requirements, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.”

D.1.9 Particulate Control [326 IAC 2-7-6(6)]

(a) Except as otherwise provided by statute or rule or in this permit, the multiclone and electrostatic precipitator (ESP) for Boiler 1 shall be in operation and control emissions at all times that the boiler, vented to that multiclone and ESP, is in operation.

(b) Except as otherwise provided by statute or rule or in this permit, the multiclone and baghouse for particulate control for Boiler 2 shall be in operation and control emissions at all times that the boiler, vented to that multiclone and baghouse, is in operation.

(c) Condition D.1.9 shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.9 shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.10 Continuous Emissions Monitoring [326 IAC 3-5] [40 CFR 64]

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A) (Continuous Monitoring of Emissions), continuous emission monitoring systems (CEMS) for Boiler 1 and Boiler 2 shall be calibrated, maintained, and operated for measuring opacity, which meet all applicable performance specifications of 326 IAC 3-5-2 and 40 CFR 64. For Boiler 1 and Boiler 2, the COMS shall be in operation in accordance with 326 IAC 3-5 and 40 CFR Part 60 when fuel is being combusted in the associated boiler.

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

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

(d) The requirement to perform continuous opacity monitoring is not applicable to Boiler 1 once it shut down and is not applicable to Boiler 2 after it is converted to natural gas.

D.1.10.1 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) **The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx 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 CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.**

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

D.1.11 Continuous Opacity Monitoring [326 IAC 3-5] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(a) 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 more than twenty-four (24) hours after the start of the malfunction or down time.

(b) 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.

(c) Method 9 readings may be discontinued once a COMS is online.

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

(e) **Condition D.1.11 – Continuous Opacity Monitoring, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.11 – Continuous Opacity Monitoring, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.**

D.1.12 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2-1]

(a) Pursuant to 326 IAC 7-2-1(c), 326 IAC 3-7, and Construction Permit PC (79) 1680, the Permittee shall demonstrate that the sulfur dioxide emissions from Boiler 1 and Boiler 2 do not exceed the emission limitations specified in Conditions D.1.3 and D.1.4, ~~using the coal sampling and analysis data as follows:~~

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, **the coal sampling and analysis data shall be as follows:**~~coal sampling and analysis data shall be collected as follows:~~

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) Pursuant to 326 IAC 3-7-2(b)(2) and 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

(3) The Permittee shall meet the minimum sampling requirements specified in 326 IAC 3-7-2(b)(3), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e).

(4) 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.

(c) 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 instead of the fuel sampling and analysis required in (b). [326 IAC 7-2-1(g)]

(d) Condition D.1.12 - Sulfur Dioxide Emissions and Sulfur Content, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.12 – Sulfur Dioxide Emissions and Sulfur Content, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

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

D.1.13 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) For Boiler 1:

(1) In the event of emissions exceeding twenty-five percent (25%) average opacity for three (3) consecutive six (6)-minute averaging periods, appropriate response steps shall be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty-five percent (25%). 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. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(2) Opacity readings in excess of twenty-five percent (25%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(b) For Boiler 2:

(1) In the event of emissions exceeding twenty percent (20)% average opacity for three (3) consecutive six (6)-minute averaging periods, appropriate response steps shall be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced, and adjustment of flue gas conditioning rate, and the baghouse being returned to service. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(2) Opacity readings in excess of twenty percent (20%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(c) Periods of elevated opacity that are subject to a Temporary Alternative Opacity Limitation (TAOL) when building a new fire in a boiler, shutting down a boiler, removing ashes from the fuel bed or furnace in a boiler, or blowing tubes, need not be included in the averaging periods for (a) and (b) of this condition.

(d) Condition D.1.13 – Opacity Readings, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.13 – Opacity Readings, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.14 Electrostatic Precipitator Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS:

(a) The ability of the ESP to control particulate emissions from Boiler 1 shall be monitored once per day, when the unit is in operation, by measuring and recording the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets.

(b) When for any one reading, operation is outside one of the normal ranges shown below, or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A voltage or current reading outside the normal range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.
Boiler 1:

(1)	Primary voltage:	275 - 430 V
(2)	Secondary voltage:	29 - 45 kV
(3)	T-R set secondary current:	150 - 405 mA

(c) Condition D.1.14 – Electrostatic Precipitator Parametric Monitoring, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned.

D.1.15 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS:

(a) The Permittee shall record the pressure drop across the baghouse used in conjunction with Boiler 2, at least once per day when the process is in operation when venting to the atmosphere. When for any one reading, the pressure drop across the baghouse is outside the normal range of 1.0 and 7.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(b) The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, and shall be calibrated or replaced in accordance with the manufacturer's specifications. The specifications shall be available on site with the Preventive Maintenance Plan.

(c) Condition D.1.15 – Baghouse Parametric Monitoring, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.15 – Baghouse Parametric Monitoring, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.16 Broken or Failed Bag Detection – Multi-Compartment Baghouse [40 CFR 64]

(a) 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.

(b) Condition D.1.16 – Broken or Failed Bag Detection, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

D.1.17 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)] [326 IAC 3-7-2] [326 IAC 3-7-3]

(a) Whenever coal sampling is not being performed and the SO_2 continuous emission monitoring system (CEMS) is being utilized to demonstrate compliance with the 24-hour emission limit for SO_2 in Condition D. 1.3(a):

If the SO_2 continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustments, for twenty-four (24) hours or more, fuel sampling shall be conducted 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.

(b) Condition D.1.17 – SO2 Monitoring System Downtime, shall no longer apply to Boiler 1 after Boiler 1 is decommissioned. Condition D.1.17 – SO2 Monitoring System Downtime, shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

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

D.1.18 Record Keeping Requirements

(a) To document the compliance status with Condition D. 1.1, the Permittee shall maintain records including the following:
  (1) Monthly records of total natural gas usage for Boiler 1 and Boiler 2.
  (2) Documentation of NO_X emission rate for the Boiler 1 and Boiler 2 gas burners.

  Note: Condition D.1.18(a) shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(b) To document the compliance status with Section C - Opacity and the particulate matter and opacity Conditions D. 1.2, D. 1.6, D. 1.8, D. 1.9, D. 1.11, D. 1.13, D. 1.14, and D. 1.15, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits in Section C - Opacity and Condition D. 1.6.

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

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6.

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

Note: Condition D.1.18(b), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(c) To document the compliance status with Condition D. 1.14, the Permittee shall maintain daily records of the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets for the ESP for Boiler 1 whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of a reading (e.g. the process did not operate that day).

Note: Condition D.1.18(c), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned.

(d) To document the compliance status with Condition D. 1.15, the Permittee shall maintain daily records of the pressure drop across the baghouse for Boiler 2 whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of a reading (e.g. the process did not operate that day).

Note: Condition D.1.18(d), shall no longer apply to Boiler 2 after Boiler 2 is converted to natural gas.

(e) To document the compliance status with SO_2 Conditions D. 1.3, D. 1.4, D. 1.12, and D. 1.17, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limits as required in Conditions D. 1.3 and D. 1.4.

(1) All fuel sampling and analysis data, pursuant to 326 IAC 7-2 or all SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g), and 40 CFR 60.45.

(2) Daily fuel usage for each of Boiler 1 and Boiler 2.

Note: Condition D.1.18(e), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(f) To document the compliance status with Conditions D.1.10.1 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain the monthly records of the NOx emissions from the combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 based on CEM data.

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

D.1.19 Reporting Requirements

(a) A quarterly report of opacity exceedances shall be submitted 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).

Note: Condition D.1.19(a), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

(b) A quarterly report of the calendar month average coal sulfur content, coal heat content, and sulfur dioxide emission rate in pounds per million British thermal units (lb/MMBtu) and the total monthly coal consumption shall be submitted not later than thirty (30) days following the end of each calendar quarter. [326 IAC 7-2-1(c)(2]
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).

Note: Condition D.1.19(b), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

~~(c) A quarterly report of the natural gas usage for Boiler 1 and Boiler 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).~~

(c) A quarterly report of the information to document the compliance status with Condition D.1.1(a) and D.1.1.1(a) 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.

(d) Whenever coal sampling is not being performed and the SO_2 continuous emission monitoring system (CEMS) is being utilized to demonstrate compliance with the 24-hour emission limit for SO_2 in Condition D.1.3(a):

Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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

Note: Condition D.1.19(d), shall no longer apply to Boiler 1 after Boiler 1 is decommissioned and to Boiler 2 after Boiler 2 is converted to natural gas.

~~(e) Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.~~

Change 3: A new Section E.4 and E.5 have been added to the permit to include the Federal rule for the natural gas-fired combustion turbine.

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:
(a) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2012, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 65.3 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).
Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.
(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 [40 CFR 60, Subpart KKKK]

E.4.1 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 combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, except as otherwise specified in 40 CFR Part 60, Subparts KKKK.

E.4.2 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 natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1 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
20. Table 1

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: **(a) One (1) natural gas-fired combustion turbine/heat recovery steam generator, identified as unit CT/HRSG1, permitted in 2012, with a combustion turbine heat input capacity, at ISO conditions, of 63.5 MMBtu per hour (HHV), equipped with dry low NOx burners, and natural gas fired duct burners, with heat input capacity at ISO conditions, of 65.3 MMBtu per hour (HHV), exhausting to stack WADE 1. CT/HRSG1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).** **Note: The heat recovery steam generator is not a source of emissions. This system is included for clarity as the operation is part of the entire source and operates in conjunction with the duct burner which is a source of emission.** **(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 [40 CFR 63, Subpart YYYY]

E.5.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines [326 IAC 20-1][40 CFR Part 63, Subpart A]

Pursuant to 40 CFR 63.6090, 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 YYYY, in accordance with the schedule in 40 CFR 63 Subpart YYYY.

E.5.2 National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines [40 CFR Part 63, Subpart YYYY][326 IAC 20]

Pursuant to CFR Part 63, Subpart, the Permittee shall comply with the provisions of 40 CFR Subpart 63, for the affected source, as specified as follows:

1. 40 CFR 63.6080
2. 40 CFR 63.6085
3. 40 CFR 63.6090
4. 40 CFR 63.6092
5. 40 CFR 63.6095
6. 40 CFR 63.6100
7. 40 CFR 63.6105
8. 40 CFR 63.6110
9. 40 CFR 63.6115
10. 40 CFR 63.6120
11. 40 CFR 63.6125
12. 40 CFR 63.6130
13. 40 CFR 63.6135
14. 40 CFR 63.6140
15. 40 CFR 63.6150
16. 40 CFR 63.6155
17. 40 CFR 63.6160
18. 40 CFR 63.6165
19. 40 CFR 63.6170

20. 40 CFR 63.6175
21. Table 1 to Subpart YYYY of Part 63
22. Table 2 to Subpart YYYY of Part 63
23. Table 3 to Subpart YYYY of Part 63
24. Table 4 to Subpart YYYY of Part 63
25. Table 5 to Subpart YYYY of Part 63
26. Table 6 to Subpart YYYY of Part 63
27. Table 7 to Subpart YYYY of Part 63

Change 4: A reporting form has been added to the permit for the natural gas usage for Boiler 2.

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

Part 70 Quarterly Report

Source Name: **Purdue University**
Emission Unit Location: **Purdue University, Wade Utility Plant, West Lafayette, Indiana, 47907-2024**
Part 70 Permit Renewal No.: **T 157-27313-00012**
Facility: **Boiler 2**
Parameter: **Natural gas usage**
Limit: **less than 2,791 million cubic feet per twelve (12) consecutive month period**

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

Submitted by: ______________________
Title / Position: ______________________
Signature: ______________________
Date: ______________________

Phone: ____

Change 5: The new emission units have beed added to Section F - CAIR of the permit.

SECTION F **Clean Air Interstate Rule (CAIR) Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-3-1(a)**

ORIS Code: 50240

CAIR Permit for CAIR Units Under 326 IAC 24-3-1(a)

After the startup of Boiler 7 this boiler, identified as Boiler 1 shall be decommissioned within one hundred and eighty (180) days:

(a1) One (1) spreader stoker coal fired boiler, identified as Boiler 1, with installation completed in 1960, with a nominal capacity of 281 MMBtu/hr, with a multi-cyclone collector and an electrostatic precipitator for particulate matter control, exhausting to stack WADE 01. Boiler 1 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 1 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After the fuel change from coal to natural gas in Boiler 2, the coal usage shall be discontinued in this boiler, identified as Boiler 2:

(b1) One (1) spreader stoker coal fired boiler, identified as Boiler 2, with installation completed in 1967, with a nominal capacity of 274 MMBtu/hr, with a multi-cyclone collector and a multi-compartment baghouse for particulate matter control, exhausting to stack WADE 02. Boiler 2 has two (2) auxiliary natural gas fired burners rated at 35 MMBtu/hr per burner, used for ignition and flame stabilization periods. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) and a continuous opacity monitor (COM).

After fuel Change to Natural Gas:

(b) One (1) natural gas fired boiler, identified as Boiler 2, constructed in 1967 and permitted to burn natural gas in 2012, with a maximum heat input capacity of 325 MMBtu per hour, equipped with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stack WADE 2. Boiler 2 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X).

....

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

F.1 Automatic Incorporation of Definitions [326 IAC 24-3-7(e)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-3-2.

....

Other Changes

Upon further review IDEM, OAQ has made the following changes to the Title V permit T157-27313-00012. (deleted language appears as ~~strikout~~ and the new language **bolded**):

Change 1: The description box heading has been changed throughout the permit.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

~~**FACILITY OPERATION CONDITIONS**~~

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

....

(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)]

....

Change 2: New Compliance Determination Requirements have been added to Sections D.4, D.5 and D.6 to make the synthetic minor limits to be federally enforceable.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emission Unit Description:

(f) One (1) natural gas fired boiler, identified as Boiler 7, permitted in 2010, with a nominal capacity of 290 MMBtu/hr, exhausting to stack WADE 03. Boiler 7 has a continuous emissions monitoring system (CEMS) for nitrogen oxides (NO_X) for compliance with NSPS requirements.

Under the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Db), Boiler 7 is considered an affected source.

(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.4.1 Boiler 7 PSD Minor Limits [326 IAC 2-2]

(a) The natural gas usage for Boiler 7 shall not exceed 2,491 million cubic feet (MMCF) per twelve (12) consecutive month period. Compliance with this limit shall be determined at the end of each month.

(b) NO_X emissions from Boiler 7 shall not exceed 0.049 pounds per million British thermal units (lb/MMBtu) of heat input.

(c) PM emissions from Boiler 7 shall not exceed 1.9 pounds per million standard cubic feet (MMCF) of natural gas.

(d) PM_{10} emissions from Boiler 7 shall not exceed 7.6 pounds per million standard cubic feet (MMCF) of natural gas.

(e) $PM_{2.5}$ emissions from Boiler 7 shall not exceed 7.6 pounds per million standard cubic feet (MMCF) of natural gas.

(f) SO_2 emissions from Boiler 7 shall not exceed 0.6 pounds per million standard cubic feet (MMCF) of natural gas.

Compliance with these emission limits combined with the potential to emit NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2 emissions from all other emission units associated with the modification to add Boiler 7 will limit the potential to emit from this modification to less than one hundred (100) tons per year of CO, less than forty (40) tons per year of NO_X, less than twenty-five (25) tons per year of PM, less than fifteen (15) tons per year of PM_{10}, less than ten (10) tons per year of $PM_{2.5}$, and less than forty (40) tons per year of SO_2. Therefore the requirements of 326 IAC 2-2 (PSD) are not applicable to the modification to add Boiler 7.

Compliance Determination Requirements

D.4.2 Compliance Determination Requirements [326 IAC 2-2]

In order to determine compliance status with Condition D.4.1 - PM, PM_{10}, $PM_{2.5}$ and SO2 — Boiler 7 PSD Minor Limits, the Permittee shall only use natural gas in Boiler 7 and compliance with the NOx emission limit shall be demonstrated on a 12-month rolling average.

D.4.3 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx 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 CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

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

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

D.4.~~2~~**4** Record Keeping Requirements

(a) To document compliance with Condition D.4.1(a), the Permittee shall maintain monthly records of natural gas usage.

(b) To document the compliance status with Condition D.4.4 - 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.

(c) In the event that a breakdown of the NOx continuous emission monitoring system (CEMS) occurs in Condition D.4.4 - 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.

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

D.4.~~3~~**5** Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.4.1(a) shall be submitted 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.

Conclusion and Recommendation

The construction of this proposed modification shall be subject to the conditions of the attached proposed PSD/Part 70 Significant Source Modification No. 157-32230-00012 Significant Permit Modification No. 157-32275-00012. 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

Limited Potential to Emit for Boiler 7, New CT/HRSG, and Boiler 2

Process	CO2e (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	CO (tpy)	Lead (tpy)	Beryllium (tpy)	Mercury (tpy)	Hexane (tpy)	Total HAP (tpy)
Boiler 7 (NG)	145,717.34	9.46	9.46	9.46	0.75	62.26	6.85	104.60	6.23E-04	1.49E-05	3.24E-04	2.24	2.35
New CT/HRSG	76,547.29	36.35	36.35	36.35	0.10	61.79	5.04	69.10					
Boiler 2 (NG)	163,303.92	10.61	10.61	10.61	0.84	213.53	7.68	71.18	6.98E-04	1.67E-05	3.63E-04	2.51	2.63
Total Future Potential	**385,568.55**	**56.42**	**56.42**	**56.42**	**1.68**	**337.58**	**19.57**	**244.87**	**0.00**	**0.00003**	**0.00**	**4.75**	**4.98**
PSD Major Modification Threshold (tpy)	**75,000**	**25**	**15**	**10**	**40**	**40**	**40**	**100**	**0.6**	**0.00040**	**0.1**	**NA**	**NA**
Triggers PSD Applicability Analysis? (Yes or No)	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**No**	**Yes**	**No**	**No**	**No**		

Emissions Netting Analysis

Emissions	CO2e (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	CO (tpy)	Lead (tpy)	Beryllium (tpy)	Mercury (tpy)	Hexane (tpy)	Total HAP (tpy)
Boiler 7 & 2 and CT/HRSG	385,568.55	56.42	56.42	56.42	1.68	337.58	19.57	244.87	0.00	0.00	0.00	4.75	4.98
Contemporaneous Increases													
Contemp Nat Gas Em Gens	22.05	0.001921	0.001921	0.001921	0.000113	0.784352	0.0226847	0.1070794	0	0	0	0.000213	0.013689
Contemp Nat Gas Boilers	4,445	0.288692	0.288692	0.288692	0.022791	3.798576	0.2089217	3.1908042	1.90E-05	4.56E-07	9.88E-06		
Contemp Diesel Em Gen < 600 hp	1658.30	3.17	3.17	3.17	2.96	44.70	3.56	9.63					0.005779
Contemp Diesel Em Gen > 600 hp	173.90	0.07	0.06	0.06	0.54	3.42	0.01	0.91					0.00168
Contemp Poultry Incinerator	284.69	0.13	0.15	0.15	1.22	0.80	0.05	0.09					
Contemporaneous Decreases (Boiler 1 Removal)	152,567	420.11	306.10	190.50	1390.19	353.44	1.5254	164.15	0.00735	0	0.00215	0	0
Net Emissions Increase	233,002.05	-363.69	-249.69	-134.08	-1,388.51	36.85	18.04	80.72	-0.01	0.00	0.00	4.75	4.98
PSD Major Modification Threshold (tpy)	**75,000**	**25**	**15**	**10**	**40**	**40**	**40**	**100**	**0.6**	**0.00040**	**0.1**	**NA**	**NA**
Triggers PSD after Netting?	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**		

Emergency Engine Hours Limit = 500 hours

Purdue University, West Lafayette, IN

Boiler 7 Potential to Emit Calculations

Steam Output = 200,000 lb/hr boiler
Heat Input = 290,000,000 mmBtu/hr
Fuels: Natural Gas

Fuel Consumption:

Natural Gas - Heat content = 1020 Btu/cu ft
Fuel Feed Rate = 284,313.73 cf/hr

AP-42 Emission Factors, Ch. 1.4, July 1998

Pollutant	Maximum rate, mmcf/hr	Emission Factor, lb/mmcf	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Maximum Actual Emissions*, ton/yr
PM (filterable)	0.284	1.9	0.5402	**2.37**	**1.76**
PM10 (filt + cond)	0.284	7.6	2.1608	**9.46**	**7.03**
SO_2	0.284	0.6	0.1706	**0.75**	**0.56**
NOx*	0.284	50	14.2157	**62.26**	**46.25**
VOC	0.284	5.5	1.5637	**6.85**	**5.09**
CO	0.284	84	23.8824	**104.60**	**77.70**
Hazardous Air Pollutants					
Lead	0.284	5.00E-04	1.42E-04	**6.23E-04**	**4.63E-04**
Beryllium	0.284	1.20E-05	3.41E-06	**1.49E-05**	**1.11E-05**
Mercury	0.284	2.60E-04	7.39E-05	**3.24E-04**	**2.41E-04**
Arsenic	0.284	2.00E-04	5.69E-05	2.49E-04	**1.85E-04**
Chromium	0.284	1.40E-03	3.98E-04	1.74E-03	**1.30E-03**
Cobalt	0.284	8.40E-05	2.39E-05	1.05E-04	**7.77E-05**
Manganese	0.284	3.80E-04	1.08E-04	4.73E-04	**3.52E-04**
Nickel	0.284	2.10E-03	5.97E-04	2.62E-03	**1.94E-03**
Selenium	0.284	2.40E-05	6.82E-06	2.99E-05	**2.22E-05**
2-Methylnaphthalene	0.284	2.40E-05	6.82E-06	2.99E-05	**2.22E-05**
3-Methylchloroanthrene	0.284	1.80E-06	5.12E-07	2.24E-06	**1.67E-06**
7,12-Dimethylbenz(a)anthracene	0.284	1.60E-05	4.55E-06	1.99E-05	**1.48E-05**
Acenapthene	0.284	1.60E-06	4.55E-07	1.99E-06	**1.48E-06**
Acenaphthylene	0.284	1.80E-06	5.12E-07	2.24E-06	**1.67E-06**
Benzene	0.284	2.10E-03	5.97E-04	2.62E-03	**1.94E-03**
Benzo(a)pyrene	0.284	1.20E-06	3.41E-07	1.49E-06	**1.11E-06**
Benzo(b)fluoranthene	0.284	1.80E-06	5.12E-07	2.24E-06	**1.67E-06**
Benzo(k)fluoranthene	0.284	1.80E-06	5.12E-07	2.24E-06	**1.67E-06**
Chrysene	0.284	1.80E-06	5.12E-07	2.24E-06	**1.67E-06**
Dibenzo(a,h)anthracene	0.284	1.20E-06	3.41E-07	1.49E-06	**1.11E-06**
Dichlorobenzene	0.284	1.20E-03	3.41E-04	1.49E-03	**1.11E-03**
Fluoranthene	0.284	3.00E-06	8.53E-07	3.74E-06	**2.78E-06**
Fluorene	0.284	2.80E-06	7.96E-07	3.49E-06	**2.59E-06**
Formaldehyde	0.284	0.08	0.02	0.09	**6.94E-02**
Hexane	**0.284**	**1.80**	**0.51**	**2.24**	**1.67E+00**
Indeno(1,2,3-cd)pyrene	0.284	1.80E-06	5.12E-07	2.24E-06	**1.67E-06**
Naphthalene	0.284	6.10E-04	1.73E-04	7.60E-04	**5.64E-04**
Phenanathrene	0.284	1.70E-05	4.83E-06	2.12E-05	**1.57E-05**
Pyrene	0.284	5.00E-06	1.42E-06	6.23E-06	**4.63E-06**
Toluene	0.284	3.40E-03	9.67E-04	4.23E-03	**3.15E-03**
Total HAP			**0.54**	**2.35**	**1.75**

* Low NOx Burners
PSD Pollutants are in bold face
Worst Case HAP in RED

Table 1 - Estimated CT/HRSG Emissions

Burns & Mac - Purdue

(1) Gas Fuel TAURUS with fired HRSG		Per Unit	Plant Total
Ambient Temperature	°F		
Fuel Type		Gas	
Assumed Fuel Sulphur Content	lb/MMBTU (HHV)	0.00	
Heat Input to Gas Turbine (Max at -9.9 deg F)	MMBtu/hr (HHV)	84.2	84.2
Heat Input from Duct Firing	MMBtu/hr (HHV)	65.3	65.3
NOx from Gas Turbine	lb/MMBTU (LHV)	0.10	
Additive NOx from Duct Firing	lb/MMBTU (HHV)	0.10	
CO from Gas Turbine	lb/MMBTU (LHV)	0.122	
Additive CO from Duct Firing	lb/MMBTU (HHV)	0.100	
UHC as CH4 from Gas Turbine	lb/MMBTU (LHV)	0.035	
Additive UHC as CH4 from Duct Firing	lb/MMBTU (HHV)	0.020	
$PM_{10}/PM_{2.5}$ Particulates from Gas Turbine	lb/MMBTU (HHV)	0.021	
Additive PM-10 Particulates from Duct Firing	lb/MMBTU (HHV)	0.100	
Gas Turbine Exhaust Emissions			
NOx	lb/hr	7.6	7.6
CO	lb/hr	9.2	9.2
UHC	lb/hr	2.7	2.7
$PM_{10}/PM_{2.5}$	lb/hr	1.8	1.8
SO_2	lb/hr	0.0	0.0
Duct Burner Exhaust Emissions			
NOx	lb/hr	6.5	6.5
CO	lb/hr	6.5	6.5
UHC	lb/hr	1.3	1.3
$PM_{10}/PM_{2.5}$	lb/hr	6.5	6.5
SO_2	lb/hr	0.0	0.0
Exhaust Emissions At Stack			
NOx	lb/MMBtu, HHV	0.094	
	lb/hr	14.1	14.1
	tons/year	61.8	61.8
CO	lb/MMBtu, HHV	0.106	
	lb/hr	15.8	15.8
	tons/year	69.1	69.1
UHC	lb/MMBtu, HHV	0.026	
	lb/hr	4.0	4.0
	tons/year	17.3	17.3
VOC	lb/MMBtu, HHV	0.008	
	lb/hr	1.2	1.2
	tons/year	5.0	5.0
$PM_{10}/PM_{2.5}$	lb/hr	8.3	8.3
	lb/MMBtu, HHV	0.056	
	tons/year	36.3	36.3
SO_2	lb/hr	0.02	0.02
	lb/MMBtu, HHV	0.00014	
	tons/year	0.1	0.1
Greenhouse Gas Emissions	lbs of CO2/MMBtu (HHV)	116.9	

General Notes
SO2 emissions depend upon the fuel's sulfur content. The SO2 estimate is based upon the assumption of 100% conversion of fuel sulphur to SO2, using assumed

Turbine Emissions Notes:
Values given above are for 8760 hours/year operation.
The table below gives the load ranges to which the turbine emissions listed above apply

Pollutant	Load Range
NOx	50 to 100%
CO	50 to 100%
UHC	50 to 100%

PM10, PM2.5, SO2, Nox, VOC and CO emissions were obtained from the manufacturer.

PM Emissons were not provided by the manufacturer but are assumed to be equal to PM10 and PM2.5.

CO2 Emissions:

Capacity	**CO2 EF***	**CO2 Emissions**
mmbtu/hr	**lbs CO2/mmbtu**	**tons/year**
149.5	116.9	76547.29

*Part 98 CO2 EF.

AP-42 emission factors were reviewed to determine if factors were available for lead, beryllium, mercury and hexane However, emission factors were not available for natural gas-fired HRSG units for these pollutants.

Boiler 2 Potential to Emit Calculations

Heat Input Capacity = 325 MMBtu/hr
Steam Output = 215,000 lb/hr boiler
Heat Input = 325,000,000 mmBtu/hr

Fuel Consumption = Natural Gas
Natural Gas - Heat content = 1020 Btu/cu ft
Maximum Fuel Feed Rate = 318,627 cf/hr
2,791 MMCF/yr

Pollutant	Maximum rate MMCF/hr	Emission Factor lb/MMCF	Maximum Uncontrolled Emission lb/hr	Maximum Uncontrolled Emission lb/MMBtu	Maximum Uncontrolled Emissions tpy
PM (filterable)	0.319	1.9	0.6054	0.0019	2.65
PM_{10} (filterable + condensable)	0.319	7.6	2.4216	0.0075	10.61
$PM_{2.5}$ (filterable + condensable)	0.319	7.6	2.4216	0.0075	10.61
SO_2	0.319	0.6	0.1912	0.0006	0.84
NOx	0.319	153	48.7500	0.1500	213.53
VOC	0.319	5.5	1.7525	0.0054	7.68
CO*	0.319	51	16.25	0.0500	71.18
CO_2	0.319	116,900	37247.55	114.6078	163,144.26
CH_4	0.319	2.2	0.70	0.0022	3.07
N_2O	0.319	0.22	0.07	0.0002	0.31
Hazardous Air Pollutants					
Lead	0.319	5.00E-04	1.59E-04	4.90E-07	6.98E-04
Beryllium	0.319	1.20E-05	3.82E-06	1.18E-08	1.67E-05
Mercury	0.319	2.60E-04	8.28E-05	2.55E-07	3.63E-04
Arsenic	0.319	2.00E-04	6.37E-05	1.96E-07	2.79E-04
Chromium	0.319	1.40E-03	4.46E-04	1.37E-06	1.95E-03
Cobalt	0.319	8.40E-05	2.68E-05	8.24E-08	1.17E-04
Manganese	0.319	3.80E-04	1.21E-04	3.73E-07	5.30E-04
Nickel	0.319	2.10E-03	6.69E-04	2.06E-06	2.93E-03
Selenium	0.319	2.40E-05	7.65E-06	2.35E-08	3.35E-05
2-Methylnaphthalene	0.319	2.40E-05	7.65E-06	2.35E-08	3.35E-05
3-Methylchloroanthrene	0.319	1.80E-06	5.74E-07	1.76E-09	2.51E-06
7,12-Dimethylbenz(a)anthracene	0.319	1.60E-05	5.10E-06	1.57E-08	2.23E-05
Acenapthene	0.319	1.60E-06	5.10E-07	1.57E-09	2.23E-06
Acenaphthylene	0.319	1.80E-06	5.74E-07	1.76E-09	2.51E-06
Benzene	0.319	2.10E-03	6.69E-04	2.06E-06	2.93E-03
Benzo(a)pyrene	0.319	1.20E-06	3.82E-07	1.18E-09	1.67E-06
Benzo(b)fluoranthene	0.319	1.80E-06	5.74E-07	1.76E-09	2.51E-06
Benzo(k)fluoranthene	0.319	1.80E-06	5.74E-07	1.76E-09	2.51E-06
Chrysene	0.319	1.80E-06	5.74E-07	1.76E-09	2.51E-06
Dibenzo(a,h)anthracene	0.319	1.20E-06	3.82E-07	1.18E-09	1.67E-06
Dichlorobenzene	0.319	1.20E-03	3.82E-04	1.18E-06	1.67E-03
Fluoranthene	0.319	3.00E-06	9.56E-07	2.94E-09	4.19E-06
Fluorene	0.319	2.80E-06	8.92E-07	2.75E-09	3.91E-06
Formaldehyde	0.319	0.08	0.02	7.35E-05	0.10
Hexane	0.319	1.80	0.57	1.76E-03	2.51
Indeno(1,2,3-cd)pyrene	0.319	1.80E-06	5.74E-07	1.76E-09	2.51E-06
Naphthalene	0.319	6.10E-04	1.94E-04	5.98E-07	8.51E-04
Phenanathrene	0.319	1.70E-05	5.42E-06	1.67E-08	2.37E-05
Pyrene	0.319	5.00E-06	1.59E-06	4.90E-09	6.98E-06
Toluene	0.319	3.40E-03	1.08E-03	3.33E-06	4.75E-03
Total HAP			0.60		**2.63**

Pollutant	Carbon Dioxide Equivalents	Combined CO2e (tpy)
CO_2	**163,144.26**	
CH_4	**64.48**	**163,303.92**
N_2O	**95.18**	

* Emission Factor for CO assumed to be 0.05 lb/mmBtu

Coal

Year	Month	Coal Use (tons)	HHV (Btu/lb)	Heat Input (MMBtu/mo)
2004	January	5084	11383	115,742
2004	February	5199	11699	121,646
2004	March	4651	11538	107,326
2004	April	6375	11773	150,106
2004	May	5450	11827	128,914
2004	June	5169	11566	119,569
2004	July	5296	11542	122,253
2004	August	5682	11933	135,607
2004	September	5674	11712	132,908
2004	October	4588	11737	107,699
2004	November	2164	11377	49,240
2004	December	5573	11594	129,227
2005	January	6204	11496	142,642
2005	February	5129	11539	118,367
2005	March	6005	12011	144,252
2005	April	5217	11846	123,601
2005	May	5700	11596	132,194
2005	June	5608	11924	133,740
2005	July	5519	11843	130,723
2005	August	5742	11912	136,797
2005	September	3960	11593	91,817
2005	October	2790	11626	64,873
2005	November	3854	11370	87,640
2005	December	5872	11154	130,993
2006	January	5611	10956	122,948
2006	February	4970	11092	110,254
2006	March	1720	11308	38,900
2006	April	5249	11080	116,318
2006	May	6139	11121	136,544
2006	June	5427	11370	123,410
2006	July	5430	11202	121,654
2006	August	5789	11101	128,527
2006	September	4793	11042	105,849
2006	October	1742	11343	39,519
2006	November	3484	10997	76,627
2006	December	5704	11142	127,108
2007	January	5926	11266	133,525
2007	February	5671	11060	125,443
2007	March	6125	11251	137,825
2007	April	6658	11127	148,167
2007	May	3848	11144	85,764
2007	June	5544	11326	125,583
2007	July	1718	11212	38,524
2007	August	1077	11116	23,944
2007	September	5027	11124	111,845
2007	October	7070	11114	157,152
2007	November	7027	11220	157,686
2007	December	6678	10913	145,754
2008	January	7403	10991	162,733
2008	February	6897	11101	153,127
2008	March	6935	10899	151,169
2008	April	3148	10896	68,601
2008	May	3858	10823	83,510
2008	June	6434	10963	141,072
2008	July	5674	10992	124,737
2008	August	6320	10983	138,825
2008	September	5460	11011	120,240
2008	October	5639	11161	125,874
2008	November	4324	11259	97,368
2008	December	6497	10920	141,894
2009	January	6290	11249	141,512
2009	February	4813	11101	106,858
2009	March	5576	11031	123,018
2009	April	1468	10892	31,979
2009	May	1924	10924	42,036
2009	June	5056	11034	111,576
2009	July	4736	11069	104,846
2009	August	4779	11153	106,600
2009	September	3628	11231	81,492
2009	October	3857	11232	86,644
2009	November	5454	10961	119,563
2009	December	5863	10884	127,626
2010	January	5770	11001	126,952
2010	February	5027	11154	112,142
2010	March	5729	11261	129,029
2010	April	1664	11103	36,951
2010	May	4402	10874	95,735
2010	June	5202	11030	114,756
2010	July	5647	11190	126,380
2010	August	5216	11302	117,902
2010	September	3285	11167	73,367
2010	October	4992	11180	111,621
2010	November	6870	10912	149,931
2010	December	6265	10934	137,003
2011	January	6329	10824	137,010
2011	February	5461	10792	117,870
2011	March	7030	10881	152,987
2011	April	1096	10919	23,934
2011	May	7099	11070	157,172
2011	June	5320	11074	117,827
2011	July	5435	11124	120,918
2011	August	5354	11086	118,709
2011	September	4551	11011	100,222
2011	October	1928	10817	41,710
2011	November	233	10811	5,038
2011	December	2873	10863	62,419
2012	January	0		0
2012	February			0
2012	March			0
2012	April			0
2012	May			0
2012	June			0
2012	July			0
2012	August			0
2012	September			0
2012	October			0
2012	November			0
2012	December			0

NOx (tons/month)*

Year	Month	Boiler 1 NOx	Unit 1 Avg Annual Total (tpy, from 2yr Total)
2004	January	31.71	
2004	February	32.65	
2004	March	24.58	
2004	April	38.67	
2004	May	32.78	
2004	June	31.36	
2004	July	34.03	
2004	August	34.79	
2004	September	39.02	
2004	October	27.82	
2004	November	12.69	
2004	December	35.69	
2005	January	36.00	
2005	February	30.41	
2005	March	38.87	
2005	April	35.80	
2005	May	32.64	
2005	June	26.85	
2005	July	27.92	
2005	August	27.80	
2005	September	18.12	
2005	October	11.24	
2005	November	18.92	
2005	December	26.49	**353.44**
2006	January	23.67	**349.42**
2006	February	20.86	**343.53**
2006	March	8.32	**335.40**
2006	April	27.09	**329.61**
2006	May	23.40	**324.92**
2006	June	25.01	**321.74**
2006	July	21.50	**315.47**
2006	August	22.79	**309.47**
2006	September	20.95	**300.44**
2006	October	6.56	**289.81**
2006	November	12.98	**289.96**
2006	December	22.46	**283.34**
2007	January	28.32	**279.50**
2007	February	25.19	**276.90**
2007	March	29.45	**272.19**
2007	April	28.43	**268.50**
2007	May	18.69	**261.52**
2007	June	28.69	**262.44**
2007	July	5.68	**251.32**
2007	August	4.57	**239.71**
2007	September	18.80	**240.04**
2007	October	32.72	**250.79**
2007	November	31.51	**257.08**
2007	December	33.79	**260.73**
2008	January	44.35	**271.07**
2008	February	42.58	**281.92**
2008	March	36.00	**295.76**
2008	April	18.18	**291.31**
2008	May	14.16	**286.69**
2008	June	31.23	**289.80**
2008	July	30.96	**294.53**
2008	August	29.13	**297.69**
2008	September	32.41	**303.42**
2008	October	29.81	**315.04**
2008	November	20.70	**318.90**
2008	December	32.13	**323.74**
2009	January	30.40	**324.77**
2009	February	20.43	**322.39**
2009	March	29.07	**322.20**
2009	April	5.93	**310.95**
2009	May	7.49	**305.35**
2009	June	23.64	**302.82**
2009	July	19.71	**309.84**
2009	August	21.31	**318.21**
2009	September	22.28	**319.95**
2009	October	19.74	**313.46**
2009	November	22.45	**308.93**
2009	December	28.83	**306.45**
2010	January	29.23	**298.89**
2010	February	25.03	**290.12**
2010	March	24.81	**284.52**
2010	April	6.20	**278.53**
2010	May	22.00	**282.45**
2010	June	21.60	**277.64**
2010	July	24.00	**274.16**
2010	August	25.70	**272.44**
2010	September	11.00	**261.74**
2010	October	27.30	**260.48**
2010	November	32.30	**266.29**
2010	December	28.70	**264.57**
2011	January	30.10	**264.42**
2011	February	20.50	**264.46**
2011	March	25.40	**262.62**
2011	April	6.10	**262.71**
2011	May	30.00	**273.96**
2011	June	26.70	**275.49**
2011	July	28.10	**279.69**
2011	August	26.70	**282.38**
2011	September	20.60	**281.54**
2011	October	7.80	**275.57**
2011	November	0.00	**264.35**
2011	December	12.80	**256.33**
2012	January	0.00	**241.72**
2012	February	0.00	**229.20**
2012	March	0.00	**216.80**
2012	April	0.00	**213.70**
2012	May	0.00	**202.70**
2012	June	0.00	**191.90**
2012	July	0.00	**179.90**
2012	August	0.00	**167.05**
2012	September	0.00	**161.55**
2012	October	0.00	**147.90**
2012	November	0.00	**131.75**
2012	December	0.00	**117.40**

Highest 24 Month Period = 353.44

SO2 (tons/month) *

Year	Month	Boiler 1 SO2	Unit 1 Avg Annual Total (tpy, from 2yr Total)
2004	January	115.99	
2004	February	77.05	
2004	March	105.21	
2004	April	121.83	
2004	May	109.46	
2004	June	89.71	
2004	July	107.40	
2004	August	114.12	
2004	September	113.96	
2004	October	103.78	
2004	November	53.17	
2004	December	113.02	
2005	January	123.40	
2005	February	117.02	
2005	March	138.18	
2005	April	153.61	
2005	May	180.06	
2005	June	149.82	
2005	July	135.60	
2005	August	137.72	
2005	September	80.31	
2005	October	48.96	
2005	November	77.41	
2005	December	153.44	**1360.11**
2006	January	137.86	**1371.05**
2006	February	115.33	**1390.19**
2006	March	34.55	**1354.86**
2006	April	121.80	**1354.85**
2006	May	129.29	**1364.76**
2006	June	99.48	**1369.64**
2006	July	100.59	**1366.24**
2006	August	103.85	**1361.10**
2006	September	90.66	**1349.45**
2006	October	29.89	**1312.51**
2006	November	62.50	**1317.18**
2006	December	105.67	**1313.50**
2007	January	120.86	**1312.23**
2007	February	103.51	**1305.48**
2007	March	119.68	**1296.23**
2007	April	116.70	**1277.77**
2007	May	75.40	**1225.44**
2007	June	121.84	**1211.45**
2007	July	28.55	**1157.93**
2007	August	25.56	**1101.85**
2007	September	69.52	**1096.45**
2007	October	151.25	**1147.60**
2007	November	133.30	**1175.54**
2007	December	138.95	**1168.30**
2008	January	155.87	**1177.30**
2008	February	145.48	**1192.38**
2008	March	123.88	**1237.04**
2008	April	62.51	**1207.40**
2008	May	72.21	**1178.86**
2008	June	127.59	**1192.92**
2008	July	133.17	**1209.21**
2008	August	125.61	**1220.08**
2008	September	124.01	**1236.76**
2008	October	125.60	**1284.62**
2008	November	87.51	**1297.12**
2008	December	129.75	**1309.16**
2009	January	118.57	**1308.02**
2009	February	83.09	**1297.81**
2009	March	96.67	**1286.30**
2009	April	27.99	**1241.95**
2009	May	31.07	**1219.78**
2009	June	82.22	**1199.97**
2009	July	80.84	**1226.12**
2009	August	73.99	**1250.34**
2009	September	62.54	**1246.84**
2009	October	62.13	**1202.28**
2009	November	71.79	**1171.53**
2009	December	103.23	**1153.66**
2010	January	94.29	**1122.88**
2010	February	94.71	**1097.50**
2010	March	103.98	**1087.55**
2010	April	26.74	**1069.66**
2010	May	86.34	**1076.72**
2010	June	62.08	**1043.96**
2010	July	46.20	**1000.48**
2010	August	73.95	**974.65**
2010	September	19.29	**922.29**
2010	October	68.20	**893.59**
2010	November	160.10	**929.89**
2010	December	109.88	**919.95**
2011	January	93.68	**907.51**
2011	February	98.63	**915.28**
2011	March	137.53	**935.71**
2011	April	33.42	**938.43**
2011	May	137.64	**991.71**
2011	June	147.94	**1024.57**
2011	July	150.92	**1059.61**
2011	August	144.11	**1094.67**
2011	September	117.28	**1122.04**
2011	October	39.56	**1110.75**
2011	November	0.00	**1074.86**
2011	December	67.07	**1056.78**
2012	January	0.00	**1009.64**
2012	February	0.00	**962.28**
2012	March	0.00	**910.29**
2012	April	0.00	**896.92**
2012	May	0.00	**853.75**
2012	June	0.00	**822.71**
2012	July	0.00	**799.61**
2012	August	0.00	**762.64**
2012	September	0.00	**752.99**
2012	October	0.00	**718.89**
2012	November	0.00	**638.84**
2012	December	0.00	**583.90**

Highest 24 Month Period = 1390.19

PM10 (tons/month) *

Year	Month	Boiler 1 PM10	Unit 1 Avg Annual Total (tpy, from 2yr Total)
2004	January	24.36	
2004	February	25.61	
2004	March	22.59	
2004	April	31.60	
2004	May	27.14	
2004	June	25.17	
2004	July	25.73	
2004	August	28.55	
2004	September	27.98	
2004	October	22.67	
2004	November	10.36	
2004	December	27.20	
2005	January	30.03	
2005	February	24.92	
2005	March	30.37	
2005	April	26.02	
2005	May	27.83	
2005	June	28.15	
2005	July	27.52	
2005	August	28.80	
2005	September	19.33	
2005	October	13.66	
2005	November	18.45	
2005	December	27.57	**300.79**
2006	January	25.88	**301.55**
2006	February	23.21	**300.35**
2006	March	8.19	**293.15**
2006	April	24.48	**289.59**
2006	May	28.74	**290.40**
2006	June	25.98	**290.80**
2006	July	25.61	**290.74**
2006	August	27.06	**289.99**
2006	September	22.28	**287.14**
2006	October	8.32	**279.97**
2006	November	16.13	**282.85**
2006	December	26.76	**282.63**
2007	January	28.11	**281.67**
2007	February	26.41	**282.41**
2007	March	29.01	**281.74**
2007	April	31.19	**284.32**
2007	May	18.05	**279.43**
2007	June	26.44	**278.58**
2007	July	8.11	**268.87**
2007	August	5.04	**256.99**
2007	September	23.54	**259.10**
2007	October	33.08	**268.81**
2007	November	33.19	**276.19**
2007	December	30.68	**277.74**
2008	January	34.26	**281.93**
2008	February	32.23	**286.44**
2008	March	31.82	**298.26**
2008	April	14.44	**293.23**
2008	May	17.58	**287.65**
2008	June	29.70	**289.51**
2008	July	26.26	**289.84**
2008	August	29.22	**290.92**
2008	September	25.31	**292.44**
2008	October	26.50	**301.52**
2008	November	20.50	**303.71**
2008	December	29.87	**305.26**
2009	January	29.79	**306.10**
2009	February	22.49	**304.15**
2009	March	25.90	**302.59**
2009	April	6.73	**290.36**
2009	May	8.85	**285.76**
2009	June	23.49	**284.28**
2009	July	22.07	**291.26**
2009	August	22.44	**299.96**
2009	September	17.15	**296.77**
2009	October	18.24	**289.35**
2009	November	25.17	**285.34**
2009	December	26.87	**283.43**
2010	January	26.72	**279.66**
2010	February	23.61	**275.35**
2010	March	27.16	**273.02**
2010	April	7.78	**269.69**
2010	May	20.15	**270.97**
2010	June	24.16	**268.20**
2010	July	26.60	**268.38**
2010	August	24.82	**266.17**
2010	September	15.44	**261.24**
2010	October	23.50	**259.74**
2010	November	31.56	**265.27**
2010	December	28.84	**264.76**
2011	January	28.84	**264.28**
2011	February	24.81	**265.44**
2011	March	32.20	**268.60**
2011	April	5.04	**267.75**
2011	May	33.08	**279.87**
2011	June	24.80	**280.53**
2011	July	25.45	**282.22**
2011	August	24.99	**283.49**
2011	September	21.10	**285.46**
2011	October	8.78	**280.74**
2011	November	1.06	**268.68**
2011	December	13.14	**261.82**
2012	January		**248.46**
2012	February		**236.65**
2012	March		**223.07**
2012	April		**219.18**
2012	May		**209.11**
2012	June		**197.03**
2012	July		**183.73**
2012	August		**171.32**
2012	September		**163.60**
2012	October		**151.85**
2012	November		**136.07**
2012	December		**121.65**

Highest 24 Month Period = 306.10

PM (tons/month) *

Year	Month	Boiler 1 PM	Unit 1 Avg Annual Total (tpy, from 2yr Total)
2004	January	34.03	
2004	February	35.76	
2004	March	31.55	
2004	April	44.13	
2004	May	37.90	
2004	June	35.15	
2004	July	35.94	
2004	August	39.87	
2004	September	39.07	
2004	October	31.66	
2004	November	14.48	
2004	December	37.99	
2005	January	41.94	
2005	February	34.80	
2005	March	42.41	
2005	April	36.34	
2005	May	38.87	
2005	June	39.32	
2005	July	38.43	
2005	August	40.22	
2005	September	26.99	
2005	October	19.07	
2005	November	25.77	
2005	December	38.51	**420.11**
2006	January	28.65	**417.42**
2006	February	25.69	**412.38**
2006	March	9.06	**401.13**
2006	April	27.10	**392.62**
2006	May	31.81	**389.58**
2006	June	28.75	**386.38**
2006	July	28.35	**382.58**
2006	August	29.95	**377.62**
2006	September	24.66	**370.41**
2006	October	9.21	**359.18**
2006	November	17.85	**360.87**
2006	December	29.62	**356.69**
2007	January	31.11	**351.27**
2007	February	29.23	**348.49**
2007	March	32.11	**343.34**
2007	April	34.52	**342.43**
2007	May	19.98	**332.99**
2007	June	29.26	**327.96**
2007	July	8.98	**313.23**
2007	August	5.58	**295.91**
2007	September	26.06	**295.44**
2007	October	36.62	**304.22**
2007	November	36.74	**309.70**
2007	December	33.96	**307.43**
2008	January	49.15	**317.68**
2008	February	46.24	**327.95**
2008	March	45.65	**346.25**
2008	April	20.72	**343.06**
2008	May	25.22	**339.76**
2008	June	42.60	**346.68**
2008	July	37.67	**351.35**
2008	August	41.93	**357.34**
2008	September	36.31	**363.16**
2008	October	38.01	**377.56**
2008	November	29.41	**383.34**
2008	December	42.85	**389.96**
2009	January	42.74	**395.77**
2009	February	32.27	**397.29**
2009	March	37.15	**399.81**
2009	April	9.66	**387.38**
2009	May	12.69	**383.73**
2009	June	33.70	**385.95**
2009	July	31.66	**397.30**
2009	August	32.19	**410.60**
2009	September	24.61	**409.88**
2009	October	26.17	**404.65**
2009	November	36.11	**404.34**
2009	December	38.54	**406.63**
2010	January	25.71	**394.91**
2010	February	22.71	**383.14**
2010	March	26.13	**373.38**
2010	April	7.48	**366.76**
2010	May	19.39	**363.84**
2010	June	23.24	**354.16**
2010	July	25.59	**348.12**
2010	August	23.88	**339.10**
2010	September	14.86	**328.37**
2010	October	22.60	**320.66**
2010	November	30.36	**321.14**
2010	December	27.74	**313.59**
2011	January	27.74	**306.09**
2011	February	23.87	**301.89**
2011	March	30.98	**298.80**
2011	April	4.85	**296.40**
2011	May	31.83	**305.97**
2011	June	23.86	**301.05**
2011	July	24.49	**297.46**
2011	August	24.04	**293.38**
2011	September	20.29	**291.22**
2011	October	8.45	**282.36**
2011	November	1.02	**264.82**
2011	December	12.64	**251.87**
2012	January	0.00	**239.01**
2012	February	0.00	**227.66**
2012	March	0.00	**214.60**
2012	April	0.00	**210.85**
2012	May	0.00	**201.16**
2012	June	0.00	**189.54**
2012	July	0.00	**176.75**
2012	August	0.00	**164.81**
2012	September	0.00	**157.38**
2012	October	0.00	**146.08**
2012	November	0.00	**130.90**
2012	December	0.00	**117.03**

Highest 24 Month Period = 420.11

PM 2.5 (tons/month) *

Year	Month	Boiler 1 PM 2.5	Unit 1 Avg Annual Total (tpy, from 2yr Total)
2004	January	15.16	
2004	February	15.94	
2004	March	14.06	
2004	April	19.66	
2004	May	16.89	
2004	June	15.66	
2004	July	16.02	
2004	August	17.76	
2004	September	17.41	
2004	October	14.11	
2004	November	6.45	
2004	December	16.93	
2005	January	18.69	
2005	February	15.51	
2005	March	18.90	
2005	April	16.19	
2005	May	17.32	
2005	June	17.52	
2005	July	17.12	
2005	August	17.92	
2005	September	12.03	
2005	October	8.50	
2005	November	11.48	
2005	December	17.16	**187.19**
2006	January	16.11	**187.66**
2006	February	14.44	**186.92**
2006	March	5.10	**182.43**
2006	April	15.24	**180.22**
2006	May	17.89	**180.72**
2006	June	16.17	**180.97**
2006	July	15.94	**180.93**
2006	August	16.84	**180.47**
2006	September	13.87	**178.70**
2006	October	5.18	**174.23**
2006	November	10.04	**176.03**
2006	December	16.65	**175.89**
2007	January	17.49	**175.29**
2007	February	16.43	**175.75**
2007	March	18.06	**175.33**
2007	April	19.41	**176.94**
2007	May	11.24	**173.90**
2007	June	16.45	**173.37**
2007	July	5.05	**167.33**
2007	August	3.14	**159.93**
2007	September	14.65	**161.25**
2007	October	20.59	**167.29**
2007	November	20.66	**171.88**
2007	December	19.09	**172.85**
2008	January	21.32	**175.45**
2008	February	20.06	**178.26**
2008	March	19.80	**185.61**
2008	April	8.99	**182.49**
2008	May	10.94	**179.01**
2008	June	18.48	**180.17**
2008	July	16.34	**180.37**
2008	August	18.19	**181.05**
2008	September	15.75	**181.99**
2008	October	16.49	**187.65**
2008	November	12.76	**189.01**
2008	December	18.59	**189.97**
2009	January	18.54	**190.50**
2009	February	14.00	**189.28**
2009	March	16.12	**188.31**
2009	April	4.19	**180.70**
2009	May	5.51	**177.84**
2009	June	14.62	**176.92**
2009	July	13.73	**181.26**
2009	August	13.96	**186.68**
2009	September	10.68	**184.69**
2009	October	11.35	**180.07**
2009	November	15.66	**177.57**
2009	December	16.72	**176.38**
2010	January	16.63	**174.04**
2010	February	14.69	**171.36**
2010	March	16.90	**169.91**
2010	April	4.84	**167.83**
2010	May	12.54	**168.63**
2010	June	15.03	**166.91**
2010	July	16.56	**167.02**
2010	August	15.45	**165.65**
2010	September	9.61	**162.58**
2010	October	14.62	**161.64**
2010	November	19.64	**165.09**
2010	December	17.95	**164.77**
2011	January	17.95	**164.47**
2011	February	15.44	**165.19**
2011	March	20.04	**167.16**
2011	April	3.14	**166.63**
2011	May	20.59	**174.17**
2011	June	15.44	**174.58**
2011	July	15.84	**175.63**
2011	August	15.55	**176.43**
2011	September	13.13	**177.65**
2011	October	5.46	**174.71**
2011	November	0.66	**167.21**
2011	December	8.18	**162.94**
2012	January	0.00	**154.62**
2012	February	0.00	**147.28**
2012	March	0.00	**138.82**
2012	April	0.00	**136.40**
2012	May	0.00	**130.13**
2012	June	0.00	**122.62**
2012	July	0.00	**114.34**
2012	August	0.00	**106.62**
2012	September	0.00	**101.81**
2012	October	0.00	**94.50**
2012	November	0.00	**84.68**
2012	December	0.00	**75.71**

Highest 24 Month Period = 190.50

CO (tons/month) *

Year	Month	Boiler 1 CO	Unit 1 Avg Annual Total (tpy, from 2yr Total)
2004	January	12.71	
2004	February	13.00	
2004	March	11.63	
2004	April	15.94	
2004	May	13.63	
2004	June	12.92	
2004	July	13.24	
2004	August	14.21	
2004	September	14.19	
2004	October	11.47	
2004	November	5.41	
2004	December	13.93	
2005	January	15.51	
2005	February	12.82	
2005	March	15.01	
2005	April	13.04	
2005	May	14.25	
2005	June	14.02	
2005	July	13.80	
2005	August	14.36	
2005	September	9.90	
2005	October	6.98	
2005	November	9.64	
2005	December	14.68	**153.13**
2006	January	14.03	**153.79**
2006	February	12.43	**153.50**
2006	March	4.30	**149.84**
2006	April	13.12	**148.43**
2006	May	15.35	**149.29**
2006	June	13.57	**149.62**
2006	July	13.58	**149.78**
2006	August	14.47	**149.92**
2006	September	11.98	**148.82**
2006	October	4.36	**145.26**
2006	November	8.71	**146.91**
2006	December	14.26	**147.07**
2007	January	14.82	**146.73**
2007	February	14.18	**147.40**
2007	March	15.31	**147.55**
2007	April	16.65	**149.35**
2007	May	9.62	**147.04**
2007	June	13.86	**146.96**
2007	July	4.30	**142.21**
2007	August	2.69	**136.38**
2007	September	12.57	**137.71**
2007	October	17.68	**143.06**
2007	November	17.57	**147.03**
2007	December	16.70	**148.03**
2008	January	18.51	**150.27**
2008	February	17.24	**152.68**
2008	March	17.34	**159.20**
2008	April	7.87	**156.58**
2008	May	9.65	**153.72**
2008	June	16.09	**154.98**
2008	July	14.19	**155.29**
2008	August	15.80	**155.95**
2008	September	13.65	**156.79**
2008	October	14.10	**161.66**
2008	November	10.81	**162.71**
2008	December	16.24	**163.70**
2009	January	15.73	**164.15**
2009	February	12.03	**163.08**
2009	March	13.94	**162.39**
2009	April	3.67	**155.91**
2009	May	4.81	**153.50**
2009	June	12.64	**152.89**
2009	July	11.84	**156.66**
2009	August	11.95	**161.29**
2009	September	9.07	**159.54**
2009	October	9.64	**155.53**
2009	November	13.64	**153.56**
2009	December	14.66	**152.54**
2010	January	14.43	**150.50**
2010	February	12.57	**148.16**
2010	March	14.32	**146.66**
2010	April	4.16	**144.80**
2010	May	11.01	**145.48**
2010	June	13.01	**143.94**
2010	July	14.12	**143.91**
2010	August	13.04	**142.53**
2010	September	8.21	**139.81**
2010	October	12.48	**139.00**
2010	November	17.18	**142.18**
2010	December	15.66	**141.89**
2011	January	15.82	**141.94**
2011	February	13.65	**142.75**
2011	March	17.58	**144.57**
2011	April	2.74	**144.10**
2011	May	17.75	**150.57**
2011	June	13.30	**150.90**
2011	July	13.59	**151.78**
2011	August	13.39	**152.49**
2011	September	11.38	**153.65**
2011	October	4.82	**151.24**
2011	November	0.58	**144.71**
2011	December	7.18	**140.97**
2012	January	0.00	**133.76**
2012	February	0.00	**127.48**
2012	March	0.00	**120.32**
2012	April	0.00	**118.24**
2012	May	0.00	**112.73**
2012	June	0.00	**106.23**
2012	July	0.00	**99.17**
2012	August	0.00	**92.65**
2012	September	0.00	**88.55**
2012	October	0.00	**82.31**
2012	November	0.00	**73.72**
2012	December	0.00	**65.89**

Highest 24 Month Period = 164.15

CO2 (tons/month) *

Year	Month	Boiler 1 CO2	Unit 1 Avg Annual Total (tpy, from 2yr Total)
2004	January	11,489	
2004	February	11,462	
2004	March	9,429	
2004	April	14,159	
2004	May	12,275	
2004	June	10,800	
2004	July	11,650	
2004	August	11,861	
2004	September	13,106	
2004	October	10,364	
2004	November	4,641	
2004	December	13,377	
2005	January	13,894	
2005	February	12,054	
2005	March	14,385	
2005	April	12,327	
2005	May	11,933	
2005	June	11,692	
2005	July	12,407	
2005	August	12,548	
2005	September	8,824	
2005	October	6,570	
2005	November	9,181	
2005	December	12,208	**136,318**
2006	January	10,906	**136,026**
2006	February	10,185	**135,387**
2006	March	3,926	**132,636**
2006	April	13,515	**132,314**
2006	May	12,357	**132,355**
2006	June	11,959	**132,934**
2006	July	11,476	**132,848**
2006	August	11,480	**132,657**
2006	September	11,043	**131,625**
2006	October	3,905	**128,395**
2006	November	8,124	**130,137**
2006	December	13,056	**129,976**
2007	January	14,628	**130,343**
2007	February	12,606	**130,619**
2007	March	15,140	**130,997**
2007	April	14,407	**132,037**
2007	May	9,883	**131,012**
2007	June	12,368	**131,350**
2007	July	2,804	**126,549**
2007	August	2,567	**121,558**
2007	September	10,354	**122,323**
2007	October	16,131	**127,104**
2007	November	15,962	**130,494**
2007	December	16,440	**132,610**
2008	January	19,656	**136,985**
2008	February	18,506	**141,146**
2008	March	16,545	**147,456**
2008	April	8,022	**144,710**
2008	May	8,012	**142,537**
2008	June	13,474	**143,295**
2008	July	13,138	**144,126**
2008	August	12,483	**144,627**
2008	September	13,476	**145,844**
2008	October	13,887	**150,835**
2008	November	10,052	**151,799**
2008	December	14,591	**152,567**
2009	January	13,509	**152,007**
2009	February	10,441	**150,925**
2009	March	13,033	**149,871**
2009	April	2,963	**144,149**
2009	May	4,473	**141,444**
2009	June	11,513	**141,016**
2009	July	10,601	**144,915**
2009	August	11,545	**149,404**
2009	September	11,504	**149,978**
2009	October	11,419	**147,622**
2009	November	11,595	**145,439**
2009	December	14,141	**144,290**
2010	January	13,969	**141,446**
2010	February	12,217	**138,301**
2010	March	12,596	**136,327**
2010	April	3,534	**134,083**
2010	May	11,378	**135,766**
2010	June	11,346	**134,702**
2010	July	12,100	**134,183**
2010	August	12,746	**134,314**
2010	September	5,978	**130,565**
2010	October	12,140	**129,692**
2010	November	14,200	**131,766**
2010	December	13,828	**131,384**
2011	January	13,876	**131,568**
2011	February	10,188	**131,441**
2011	March	12,116	**130,983**
2011	April	2,923	**130,963**
2011	May	13,330	**135,392**
2011	June	12,381	**135,826**
2011	July	13,681	**137,366**
2011	August	12,792	**137,989**
2011	September	10,810	**137,643**
2011	October	4,016	**133,941**
2011	November	5	**128,146**
2011	December	6,956	**124,554**
2012	January	0	**117,569**
2012	February	0	**111,461**
2012	March	0	**105,163**
2012	April	0	**103,396**
2012	May	0	**97,707**
2012	June	0	**92,033**
2012	July	0	**85,983**
2012	August	0	**79,611**
2012	September	0	**76,622**
2012	October	0	**70,552**
2012	November	0	**63,452**
2012	December	0	**56,538**

Highest 24 Month Period = 152,567

Natural Gas Fired Emergency Generators Added in Last 5 Years

Location	Make	Model #	hp	MMBtu/hr	Date
ASREC Dairy	NA	NA	302	0.769	9/9/2011
Total			**302.00**	**0.769**	

Allowed hours operated per year = 500 hours

Emissions Factors from AP-42 Table 3.2-2, 4 Stroke Lean Burn Engines

PM/PM10/PM2.5 (filterable + condensable	**0.00999**	lb/MMBtu
SO2	**0.000588**	lb/MMBtu
NOx	**4.08**	lb/MMBtu
VOC	**0.118**	lb/MMBtu
CO	**0.557**	lb/MMBtu
Benzene	0.00044	lb/MMBtu
Toluene	0.000408	lb/MMBtu
Xylenes	0.000184	lb/MMBtu
Methanol	0.0025	lb/MMBtu
1,3 Butadiene	0.000267	lb/MMBtu
Formaldehyde	0.0528	lb/MMBtu
Acetaldehyde	0.00836	lb/MMBtu
Acrolein	0.00514	lb/MMBtu
n-Hexane	0.00111	lb/MMBtu
Total HAP	**0.0712**	lb/MMBtu
Emission Factors for GHG Emissions		
CO2	**116,900.0000**	lb/mmcf
CH4	**2.2000**	lb/mmcf
N2O	**0.2200**	lb/mmcf

Total Emergency Combustion Emissions	lb/hr	max hours/ year	tpy
CO2e	**88.22**	**500**	**22.05**
PM/PM10/PM2.5 (filterable + condensable)	**0.01**	**500**	**0.0019**
SO2	**0.0005**	**500**	**0.0001**
NOx	**3.14**	**500**	**0.7844**
VOC	**0.09**	**500**	**0.0227**
CO	**0.43**	**500**	**0.1071**
Hazardous Air Pollutants			
Benzene	3.38E-04	**500**	0.0001
Toluene	3.14E-04	**500**	0.0001
Xylenes	1.41E-04	**500**	0.0000
Methanol	1.92E-03	**500**	0.0005
1,3 Butadiene	2.05E-04	**500**	0.0001
Formaldehyde	**4.06E-02**	**500**	**0.0102**
Acetaldehyde	6.43E-03	**500**	0.0016
Acrolein	3.95E-03	**500**	0.0010
n-Hexane	8.54E-04	**500**	0.0002
Total HAP	**5.48E-02**	**500**	**0.0137**

Diesel Fired Emergency Generators > 600 hp Added in Last 5 Years

Location	Contact	Make	Model #	Install Date	kW
HOCK (Structural Biology) *		Katolight	304508-1-1-0209	9/22/2009	750
ARMS		Caterpillar	3456	7/10/2007	500
Total					

Allowed hours per year = 500 hours

Emissions Factors from AP-42 Table 3.4-1	*Additional Notes*		
PM	*Table 3.4-2*	**0.0697**	lb/MMBtu
PM10/PM2.5 (filterable + condensable)	*Table 3.4-2*	**0.0573**	lb/MMBtu
SO2 *	*1.01 x (S=0.5) = 0.505*	**0.505**	lb/MMBtu
NOx		**3.2**	lb/MMBtu
VOC (as TOC)		**0.0081**	lb/MMBtu
CO		**0.85**	lb/MMBtu
CO2	*Part 98, Table C-1*	**162.9**	lb/MMBtu
Benzene	*Table 3.4-3*	0.000776	lb/MMBtu
Toluene	*Table 3.4-3*	0.000281	lb/MMBtu
Xylenes	*Table 3.4-3*	0.000193	lb/MMBtu
Propylene	*Table 3.4-3*	0.00279	lb/MMBtu
Formaldehyde	*Table 3.4-3*	0.0000789	lb/MMBtu
Acetaldehyde	*Table 3.4-3*	0.0000252	lb/MMBtu
Acrolein	*Table 3.4-3*	0.00000788	lb/MMBtu
Total PAH	*Table 3.4-4*	0.000212	lb/MMBtu
Total HAP		**0.0044**	lb/MMBtu

Total Emergency Combustion Emissions	lb/hr	max hours/ year	tpy
PM	**0.30**	**500**	**0.07**
PM10/PM2.5	**0.24**	**500**	**0.06**
SO2	**2.16**	**500**	**0.54**
NOx	**13.66**	**500**	**3.42**
VOC	**0.03**	**500**	**0.01**
CO	**3.63**	**500**	**0.91**
CO2	**695.60**	**500**	**173.90**
Hazardous Air Pollutants			
Benzene	3.31E-03	500	0.0008
Toluene	1.20E-03	500	0.0003
Xylenes	8.24E-04	500	0.0002
Formaldehyde	3.37E-04	500	0.0001
Acetaldehyde	1.08E-04	500	0.0000
Acrolein	3.36E-05	500	0.0000
Total PAH	9.05E-04	500	0.0002
Total HAP	**6.72E-03**	500	**0.0017**

Diesel Fired Emergency Generators < 600 hp Added in Last 5 Years

Location	Make	Model #	Install Date	kW	hp
MANN (e-entr)	Kohler	TAD1242GE	1/17/2007	375	503
PRSV	Katolight	PE4020T117915	6/28/2007	20	27
EE	Cummins	QSL9-G2 NP3	10/8/2007	100	134
PGMD (MCutParking)	Kohler	400REOZVC	12/13/2007	400	536
WDCT	Katolight	5030TF270C	5/15/2008	40	54
WTHR upgrade			1/29/2009	150	201
WADE DG4			5/15/2009	400	536
LFPU (Replace student housing)	Cummins		7/17/2009	300	402
DISC (disc. Learning)			10/23/2009	150	201
LILLY			6/29/2011	300	402
MARRIOT			7/8/2011	100	134
ME Gatewood Addition			8/1/2011	125	168
MACKEY EXPANSION		Cummins DFEG 350	10/20/2011	350	469
ELLT (new)	MTU onsite	DS00300D6SP	8/1/2012	300	460
HANSON			?	100	134
HERRICK			?	350	469
REC Sports exp			???	400	536
DRUG DISCOVERY			1st Q 2013	300	402
Total					**5,768**

Allowed hours per year = 500 hours

Emissions Factors from AP-42 Table 3.4-1	***Additional Notes***		
PM	*Table 3.3-1*	**0.0022**	lb/hp-hr
PM10/PM2.5 (filterable + condensable)	*Table 3.3-1*	**0.0022**	lb/hp-hr
SO2 *	*Table 3.3-1*	**0.00205**	lb/hp-hr
NOx	Table 3.3-1	**0.031**	lb/hp-hr
VOC (as TOC)	Table 3.3-1	**0.00247**	lb/hp-hr
CO	Table 3.3-1	**0.00668**	lb/hp-hr
CO2	Table 3.3-1	**1.15**	lb/hp-hr
Benzene	*Table 3.3-2*	0.000776	lb/MMBtu
Toluene	*Table 3.3-2*	0.000281	lb/MMBtu
Xylenes	*Table 3.3-2*	0.000193	lb/MMBtu
Formaldehyde	*Table 3.3-2*	0.0000789	lb/MMBtu
Acetaldehyde	*Table 3.3-2*	0.0000252	lb/MMBtu
Acrolein	*Table 3.3-2*	0.00000788	lb/MMBtu
Total PAH	*Table 3.3-2*	0.000212	lb/MMBtu
Total HAP		**0.0016**	lb/MMBtu

Total Emergency Combustion Emissions	lb/hr	max hours/ year	tpy
PM	**12.69**	**500**	**3.17**
PM10/PM2.5	**12.69**	**500**	**3.17**
SO2	**11.82**	**500**	**2.96**
NOx	**178.81**	**500**	**44.70**
VOC	**14.25**	**500**	**3.56**
CO	**38.53**	**500**	**9.63**
CO2	**6633.20**	**500**	**1658.30**
Hazardous Air Pollutants			
Benzene	1.14E-02	500	0.0028
Toluene	4.13E-03	500	0.0010
Xylenes	2.83E-03	500	0.0007
Formaldehyde	1.16E-03	500	0.0003
Acetaldehyde	3.70E-04	500	0.0001
Acrolein	1.16E-04	500	0.0000
Total PAH	3.11E-03	500	0.0008
Total HAP	**2.31E-02**	500	**0.0058**

Natural Gas Fired Combustion (for boilers replaced in past 5 years)

ID	Location	Natural Gas Boilers		
ZL3	Zucrow Labs	2 @ 0.745 MMBtu/hr =	1.49	MMBtu/hr
	Airport	2 @ 2.0 mmBtu/hr =	4	MMBtu/hr
B601	Baker Farm	2 @ 0.1 MMBtu/hr =	0.2	MMBtu/hr
B404	Baker Farm	4 @ 0.15 MMBtu/hr =	0.6	MMBtu/hr
B405	Baker Farm	4 @ 0.1 MMBtu/hr =	0.4	MMBtu/hr
CHAF	Chaffee	2 @ 0.327 MMBtu/hr =	0.654	MMBtu/hr
SLAY-DAIRY	Slayton Dairy Farm	2 @ 0.751 MMBtu/hr -	1.502	MMBtu/hr
		TOTALS	**8.846**	**MMBtu/hr**

Fuel Consumption:

Natural Gas - Heat content =	1020	Btu/cu ft
Fuel Feed Rate =	0.00867	mmcf/hr

AP-42 Emission Factors, Tables 1-4.1,4.2,4.4

Pollutant	Maximum rate (mmcf/hr)	Emission Factor (lb/mmcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (ton/yr)
CO2	0.00867	116900	1013.82098	4,440.54
CH4 (CO2e)	0.00867	46.2	0.400671765	1.75
N2O (CO2e)	0.00867	68.2	0.591467843	2.59
Total GHG				4,445
PM/PM10/PM2.5	0.00867	7.6	0.0659	0.289
SO_2	0.00867	0.6	0.0052	0.023
NOx	0.00867	100	0.8673	3.799
VOC	0.00867	5.5	0.0477	0.209
CO	0.00867	84	0.7285	3.191
Lead	0.00867	5.00E-04	4.34E-06	1.90E-05
Beryllium	0.00867	1.20E-05	1.04E-07	4.56E-07
Mercury	0.00867	2.60E-04	2.25E-06	9.88E-06

Hexane

Total HAP

Poultry Incinerator Emissions

						Potential to Emit						
Emission Unit	**Maximum Capacity**	**Pollutant**	**Emission Factor**	**Units**	**Source of EF**	**PM (TPY)**	**$PM_{10}/PM_{2.5}$ (TPY)**	**SO2 (TPY)**	**NOx (TPY)**	**VOC (TPY)**	**CO (TPY)**	**CO2 (TPY)**
Animal Incinerator	307	PM	0.024	lb/hr	Stack Test data from a similar unit	0.1051	0.1051	0.3327	0.5457	0.0458	0.0263	
	tpy	PM-10	0.024	lb/hr	Assumed the same as PM emissions							
70 lb/hr @8760 hrs/yr = 307 tpy		SO2	2.17	lb/ton	AP-42 Table 2.3-1							
		NOx	3.56	lb/ton	AP-42 Table 2.3-1							
		VOC	0.299	lb/ton	AP-42 Table 2.3-2							
		CO	0.006	lb/hr	Stack Test data from a similar unit							
Animal Incinerator (Fuel Oil)	0.0029	PM	2	lb/kgal	AP-42 Table 1,3-1	0.0250	0.0412	0.8863	0.2497	0.0042	0.0624	284.6873
	kgal/hour	PM-10	3.3	lb/kgal	AP-42 Table 1.3-1 and 1.3-2							
Capacity: 1.5 gal/hr (primary burner)		SO2	142*S	lb/kgal	AP-42 Table 1.3-1							
1.35 gal/hr afterburner		NOx	20	lb/kgal	AP-42 Table 1.3-1							
2.85 gal/hour		VOC	0.34	lb/kgal	AP-42 Table 1.3-3							
Assumed S = 0.5		CO	5	lb/kgal	AP-42 Table 1.3-1							
		CO2	162.9	lb/mmBtu	Part 98, Table C-1							
Total Emissions						**0.130**	**0.15**	**1.22**	**0.80**	**0.05**	**0.09**	**284.69**

NOx Emissions from Power Plant in the year 2004

2004	UNIT1			UNIT 2			UNIT 3			UNIT 5		
MONTH	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)
JANUARY	63418.56	31.71	85.24	57462.34	28.73	77.23	3759.84	1.88	5.05	16221.06	8.11	21.80
FEBRUARY	65291.97	32.65	93.81	55079.17	27.54	79.14	251.92	0.13	0.36	11338.98	5.67	16.29
MARCH	49169.14	24.58	66.09	56027.78	28.01	75.31	0.00	0.00	0.00	11500.66	5.75	15.46
APRIL	77334.33	38.67	107.41	58037.59	29.02	80.61	254.59	0.13	0.35	2926.55	1.46	4.06
MAY	65569.26	32.78	88.13	23844.89	11.92	32.05	0.20	0.00	0.00	16884.53	8.44	22.69
JUNE	62729.82	31.36	87.12	83605.25	41.80	116.12	0.00	0.00	0.00	19985.40	9.99	27.76
JULY	68069.92	34.03	91.49	79035.56	39.52	106.23	112.24	0.06	0.15	22913.62	11.46	30.80
AUGUST	69580.96	34.79	93.52	53448.04	26.72	71.84	531.59	0.27	0.71	21380.47	10.69	28.74
SEPTEMBER	78036.54	39.02	108.38	66302.20	33.15	92.09	1025.45	0.51	1.42	6286.70	3.14	8.73
OCTOBER	55630.83	27.82	74.77	60605.66	30.30	81.46	3.57	0.00	0.00	11272.98	5.64	15.15
NOVEMBER	25383.87	12.69	35.26	62135.66	31.07	86.30	469.14	0.23	0.65	13410.28	6.71	18.63
DECEMBER	71376.25	35.69	95.94	55754.11	27.88	74.94	839.74	0.42	1.13	15368.09	7.68	20.66
TOTAL	751591.46	375.80	85.60	711338.26	355.67	81.11	7248.29	3.62	0.82	169489.33	84.74	19.23

2004 Boilers 1 and 2 **39 lbs SO2/Ton coal**

Date	Coal Heat Value (Btu/lb)	Nat Gas Heat Value (Btu/ft^3)	Boiler 1 Coal (ton)	% sulfur by weight	lbs SO2/ Mbtu	=39*% S * ton coal/2000 Boiler 1 Tons SO2 emitted	ash as rec.	Boiler 1 Nat Gas therm	Boiler 1 Nat Gas (ft^3)	Boiler 1 Hours	Boiler 1 (mmBtu/hr)	Boiler 2 Coal (ton)	Blr 1+2	Boiler 2 Nat Gas therm	Boiler 2 Nat Gas (MMft^3)	Tons SO2 emitted	=39*% S * ton coal/2000 Boiler 2 Boiler 2 Hours	Boiler 2 (mmBtu/hr)	stoker coal cl (ug/g)	stoker coal Hg (ug/g)
Jan-04	11383	1012	5084	1.17	2.000	115.99	5.97	5743.00	0.567	692.00	167.26	4847.00	9931.00	0.00	0.000	110.58	744.00	148.32		
Feb-04	11699	1012	5199	0.76	1.270	77.05	4.76	0.00	0.000	696	174.78	4686	9885.00	0	0.000	69.45	696	157.53		0.06
Mar-04	11538	1012	4651	1.16	1.960	105.21	6.26	9809.00	0.969	595	180.38	5665	10316.00	0	0.000	128.14	744	175.71		0.1
Apr-04	11773	1012	6375	0.98	1.330	121.83	5.27	16784.00	1.658	720	208.48	5550	12425.00	1896	0.188	106.06	692	188.84		0.09
May-04	11827	1012	5450	1.03	1.700	109.46	5.14	8518.00	0.842	744	173.27	1463	6913.00	4381	0.434	29.38	251	137.87	211	0.06
Jun-04	11566	1012	5169	0.89	1.500	89.71	5.96	100.00	0.010	720	166.07	4819	9988.00	0	0.000	83.63	720	154.82	195	0.06
Jul-04	11542	1012	5296	1.04	1.760	107.40	6.26	0.00	0.000	744	164.32	4650	9946.00	0	0.000	94.30	744	144.28	73	0.06
Aug-04	11933	1012	5682	1.03	1.680	114.12	4.93	663.00	0.066	744	182.27	4797	10479.00	6804	0.674	96.35	698	164.02	30	0.16
Sep-04	11712	1012	5674	1.03	1.710	113.96	5.96	1897.00	0.187	720	184.59	5587	11261.00	0	0.000	112.21	720	181.76	28	0.03
Oct-04	11737	1012	4588	1.16	1.930	103.78	5.22	8635.00	0.853	555	194.05	5216	9804.00	3661	0.362	117.99	650	188.37	209	0.13
Nov-04	11377	1012	2164	1.26	2.160	53.17	6.44	5994.00	0.592	264	186.51	6089	8253.00	0	0.000	149.61	720	192.43	81	0.1
Dec-04	11594	1012	5573	1.04	1.750	113.02	5.86	132.00	0.013	744	173.69	5071	10644.00	261	0.026	102.84	744	158.05	52	0.06
	11640.08333		60905	1.04583333	1.729	1225	5.669167	58275	5.758	7938		58440	119845	17003	1.683	1201	8123		109.875	0.0827273

2004 NOx Blr 1	753367.4	lbs	376.68	tons
2004 NOx Blr 2	710965.1	lbs	355.48	tons
2004 PM Blr 1	**833712.5879**	**lbs**	**416.8562939**	
2004 PM Blr 2	85711.05522	lbs	42.85552761	

	HCl TPY	HF EF= 0.15 lb/ton coal
Blr 1	**0**	**4.567875**
Blr 2	**0**	**4.383**

2004 Boiler #5

Date	Coal Heat Value (Btu/lb)	% Sulfur by weight in Coal	From CEMS SO2 lb/Mbtu 30-day roll ave	SO2 tons emitted	ash content as received	Nat gas (therms)	Nat gas MMft^3	Boiler 5 Coal (ton)	Boiler 5 Hours	Boiler 5 (mmBtu/hr)	Boiler 5 limestone(tons	Boiler 5 Cl (ug/g)	Boiler 5 Hg (ug/g)
January-04	10956	2.36	0.302	21.0764954	8.14	0	0	6370	744	187.606774	902		
February-04	11149	2.16	0.306	20.8346046	7.35	0	0	6107	696	195.652135	974		0.12
March-04	11037	2.22	0.315	19.681344	7.94	0	0	5661	639	195.556986	645		0.12
April-04	10982	2.19	0.316	1.51999666	7.79	29	0.002866	438	48	200.4215	89		0.1
May-04	11077	2.51	0.335	21.2368798	7.8	0	0	5723	725	174.879092	922	435	0.11
June-04	11051	2.31	0.322	17.8775121	7.38	0	0	5024	720	154.222844	714	458	0.1
July-04	11084	2.3	0.303	18.1658669	7.3	0	0	5409	744	161.164935	776	343	0.06
August-04	10983	2.22	0.297	19.238987	8.21	0	0	5898	744	174.133694	832	214	0.09
September-04	11020	2.4	0.32	7.211488	8.42	0	0	2045	242	186.247107	329	308	0.1
October-04	11084	2.42	0.343	16.3858097	7.82	0	0	4310	464	205.913966	851	308	0.1
November-04	10983	2.28	0.314	25.0890161	7.51	0	0	7275	720	221.948125	1051	367	0.1
December-04	11020	2.29	0.308	22.3301786	7.39	0	0	6579	744	194.894032	1069	206	0.11
totals	11035.5	2.305	0.315083333	210.648179	7.75416667	29	0.002866	60839	7230		9154	329.875	0.100909

						HCl TPY	Hg TPY	HF EF= 0.15 lb/ton coal
2004 CO blr 5	11.41360934							
2004 NOx blr 5	171265.3	lbs	85.63265	tons		19.51871332	0.006139	4.562925
2004 PM blr 5	4.699721492					1.951871332	0.000614	0.4562925

NOx Emissions from Power Plant in the year 2005

2005	UNIT1			UNIT 2			UNIT 3			UNIT 5		
MONTH	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)
JANUARY	72006.32	36.00	96.78	59300.57	29.65	79.71	761.09	0.38	1.02	18437.56	9.22	24.78
FEBRUARY	60821.06	30.41	90.51	53596.17	26.80	79.76	0.00	0.00	0.00	12266.65	6.13	18.25
MARCH	77746.19	38.87	104.50	68231.53	34.12	91.71	631.98	0.32	0.85	8259.85	4.13	11.10
APRIL	71607.00	35.80	99.45	13147.26	6.57	18.26	0.00	0.00	0.00	18305.41	9.15	25.42
MAY	65287.35	32.64	87.75	2691.17	1.35	3.62	519.12	0.26	0.70	15833.27	7.92	21.28
JUNE	53705.74	26.85	74.59	46998.26	23.50	65.28	0.00	0.00	0.00	17605.88	8.80	24.45
JULY	55843.09	27.92	75.06	51298.58	25.65	68.95	0.00	0.00	0.00	15214.18	7.61	20.45
AUGUST	55596.13	27.80	74.73	51813.33	25.91	69.64	0.00	0.00	0.00	17211.33	8.61	23.13
SEPTEMBER	36249.08	18.12	50.35	47237.91	23.62	65.61	8.29	0.00	0.01	20199.63	10.10	28.06
OCTOBER	22478.32	11.24	30.21	51710.18	25.86	69.50	895.22	0.45	1.20	9516.51	4.76	12.79
NOVEMBER	37833.53	18.92	52.55	42147.19	21.07	58.54	1756.17	0.88	2.44	19141.51	9.57	26.59
DECEMBER	52985.01	26.49	71.22	52228.92	26.11	70.20	136.26	0.07	0.18	11182.86	5.59	15.03
TOTAL	662158.82	331.08	75.64	540401.06	270.20	61.73	4708.13	2.35	0.53	183174.64	91.59	20.95

2005 Boilers 1 and 2

39 lbs SO2/Ton coal

Date	Coal Heat Value (Btu/lb)	Nat Gas Heat Value (Btu/ft^3)	Boiler 1 Coal (ton)	% sulfur by weight	lbs SO2/ Mbtu	=39*% S * ton coal/2000 Boiler 1 Tons SO2 emitted	ash as rec.	Boiler 1 Nat Gas therm	Boiler 1 Nat Gas (mmft^:	Boiler 1 Hours	Boiler 1 (mmBtu/hr)	Boiler 2 Coal (ton)	Blr 1+2	Boiler 2 Nat Gas th	Boiler 2 Nat Gas (M	Tons SO2 emitted	=39*% S * ton coal/2000 Boiler 2 Boiler 2 Hours	Boiler 2 (mmBtu/hr	stoker coa cl (ug/g)	stoker coal Hg (ug/g)	
January-05	11496	1012	6204.00	1.02	1.73	123.39756	6.06	0.000	0.00	744	191.72	5909.000	12113.00	2096.00	0.00	117.53	744.00	182.607	171.00	0.06	
February-05	11539	1012	5129.00	1.17	1.98	117.018135	6.8	1652.000	0.16	672	176.14	5013.000	10142	0.00	0	114.37	672	172.158	104.00	0.07	
March-05	12011	1012	6005.00	1.18	1.92	138.17505	5.38	26548.000	2.62	744	193.89	5990.000	11995	0.00	0	137.83	744	193.403	109.00	0.12	
April-05	11846	1012	5217.00	1.51	2.49	153.614565	5.49	4159.000	0.41	720	171.67	1338.000	6555	574.00	0.056832	39.40	177	179.095	61.00	0.12	
May-05	11596	1012	5700.00	1.62	2.72	180.063	6.53	12700.000	1.25	744	177.68	524.000	6224	5527.00	0.547228	16.55	96	126.590	136.00	0.17	
June-05	11924	1012	5608.00	1.37	2.24	149.81772	5.42	1024.000	0.10	720	185.75	5046.000	10654	0.00	0	134.80	720	167.135	129.00	0.1	
July-05	11843	1012	5519.00	1.26	2.07	135.60183	5.49	5725.000	0.57	744	175.70	5224.000	10743	0.00	0	128.35	744	166.311	133.00	0.13	
August-05	11912	1012	5742.00	1.23	2.01	137.72187	5.33	313.000	0.03	744	183.87	5536.000	11278	796.00	0.078812	132.78	744	177.271	107.00	0.13	
September-05	11593	1012	3960.00	1.04	1.75	80.3088	5.64	2919.000	0.29	576	159.40	5298.000	9258	0.00	0	107.44	720	170.610	109.00	0.1	
October-05	11626	1012	2790.00	0.9	1.51	48.9645	5.66	13861.000	1.37	377	172.08	5711.000	8501	66.00	0.006535	100.23	744	178.484	82.00	0.08	
November-05	11370	1012	3854.00	1.03	1.77	77.40759	6.05	15228.000	1.50	516	169.84	4590.000	8444	2550.00	0.252475	92.19	600	173.961	207.00	0.08	
December-05	11154	1012	5872.00	1.34	2.41	153.43536	7.68	227.000	0.02	744	176.07	5827.000	11699	0.00	0	152.26	744	174.716	240.00	0.06	
	11659.16667		61600.00	1.2225		1495.52598	5.960833333	84356.000	8	8045.00		56006.000	117606	11609.00	0.941881	1273.742	7449		143	0	0.00 lb/mmBtu Hg
						1430.814										1300.879					HF EF=
																		HCl TPY	Hg TPY	Hg TPY (c	0.15 lb/ton coal
																	Blr 1	6.582628	0.006496		**4.62**
																	Blr 2	5.984848	0.005906		**4.20045**

2005 NOx Blr 1	658677.2	lbs		329.34	tons
2005 NOx Blr 2	540543.2	lbs		270.27	tons
2005 PM Blr 1	**844608.688**	**lbs**		**422.30**	tons
2005 PM Blr 2	**82275.89433**	**lbs**		**41.14**	tons
	Blr 1	%annual	Blr 2	%annual	
1st Q Coal	17338	28.1461039	16912.00	30.19676463	
2nd Q Coal	16525	26.8262987	6908.00	12.33439274	
3rd Q coal	15221	24.70941558	16058.00	28.67192801	
4th Q coal	12516	20.31818182	16128.00	28.79691462	

2005 Boiler #5

Date	Coal Heat Value (Btu/lb)	% Sulfur by weight in Coal	From CEMS SO2 lb/Mbtu 30-day roll ave	SO2 tons emitted	ash content as received	Nat gas (therms)	Nat gas MMft^3	Boiler 5 Coal (ton)	Boiler 5 Hours	Boiler 5 (mmBtu/hr)	Boiler 5 limestone(tons	Boiler 5 Cl (ug/g)	Boiler 5 Hg (ug/g)	
January-05	10957	2.14	0.296	19.7839592	7.03	0	0	6100	744	179.6712366	819	363	0.09	
February-05	10999	2.17	0.295	18.3001362	7.06	0	0	5640	672	184.6260714	684	361	0.09	
March-05	11082	2.12	0.302	7.42981608	6.99	0	0	2220	274	179.5769343	296	267	0.09	
April-05	11058	2.1	0.3	17.7381378	7.33	22	0.002173913	5347	635	186.2271685	837	301	0.1	
May-05	11149	2.18	0.289	20.74362872	6.99	0	0	6438	720	199.3812833	879	306	0.11	
June-05	11039	2.17	0.298	19.49101035	7.53	0	0	5925	720	181.6835417	845	263	0.11	
July-05	11618	2.74	0.361	26.48992297	7.04	0	0	6316	744	197.2561505	1125	185	0.1	
August-05	11406	2.77	0.371	26.65501217	7.71	0	0	6299	744	193.1354677	1157	87	0.08	
September-05	11386	2.87	0.377	25.70362174	7.8	0	0	5988	720	189.3871333	1141	50	0.09	
October-05	11586	2.84	0.38	14.09738136	6.63	0	0	3202	360	206.1020667	588	119	0.1	
November-05	11175	2.96	0.359	21.99683648	8.62	0	0	5483	624	196.3862981	1158	145	0.1	
December-05	10820	2.63	0.357	27.59155182	10.28	0	0	7143	744	207.7614516	1237	128	0.09	
totals/averages	11189.58333	2.474166667	0.332083333	246.0210149	7.58416667		0.002173913	66101	7701		10766	214.5833333	0.095833	
														HF EF=
2005 CO blr 5	12.57392501	tons										HCl TPY	Hg TPY	0.15 lb/ton coal
2005 NOx blr 5	183106.7	lbs	91.55335	tons								13.7950644	0.006335	4.957575
2005 PM blr 5	5.177498535	tons										1.37950644	0.000633	0.495758

	BLR 5	%annual
1st Q Coal	13960	21.11919638
2nd Q Coal	17710	26.79233295
3rd Q coal	18603	28.14329587
4th Q coal	15828	23.94517481

Actual stack test shows 0.0018-0.0014 lb HF/ton coal
Mostardi Platt 2001

NOx Emissions from Power Plant in the year 2006

2006	UNIT1			UNIT 2			UNIT 3			UNIT 5		
MONTH	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)	SUM (lbs)	tons	AVERAGE (lb/hr)
JANUARY	47348.86	23.67	63.81	49869.72	24.93	67.21	0.08	0.00	0.00	10192.13	5.10	13.74
FEBRUARY	41729.64	20.86	62.38	44379.48	22.19	66.34	2.46	0.00	0.00	11378.61	5.69	17.01
MARCH	16635.77	8.32	22.42	32375.53	16.19	43.63	727.11	0.36	0.99	9255.67	4.63	20.12
APRIL	54188.26	27.09	75.37	0.00	0.00	0.00	44.85	0.02	0.06	9255.67	4.63	12.87
MAY	46802.97	23.40	63.76	51451.47	25.73	69.16	0.00	0.00	0.00	0.00	0.00	0.00
JUNE	50013.63	25.01	69.46	49313.77	24.66	68.49	0.19	0.00	0.00	7165.91	3.58	9.95
JULY	43000.29	21.50	61.52	50965.27	25.48	68.50	0.00	0.00		20498.14	10.25	27.55
AUGUST	45587.94	22.79	61.27	53686.83	26.84	72.16	0.83	0.00	0.00	20523.08	10.26	27.58
SEPTEMBER	41907.34	20.95	58.37	47565.94	23.78	66.06	0.45	0.00	0.00	12447.90	6.22	17.29
OCTOBER	13125.82	6.56	17.64	36723.99	18.36	49.36	0.00	0.00	0.00	16429.28	8.21	22.08
NOVEMBER	25958.97	12.98	36.05	33851.18	16.93	47.02	2.03	0.00	0.00	13936.68	6.97	19.36
DECEMBER	44918.85	22.46	60.37	48398.75	24.20	65.05	584.57	0.29	0.79	12879.90	6.44	17.31
TOTAL	471218.34	235.61	54.37	498581.94	249.29	56.91	1362.57	0.68	0.17	143962.97	71.98	17.07

2006 Boilers 1 and 2

39 lbs SO2/Ton coal

Date	Coal Heat Value (Btu/lb)	Nat Gas Heat Value (Btu/ft^3)	Boiler 1 Coal (ton)	% sulfur by weight	lbs SO2/ Mbtu	=39*% S * ton coal/2000 Boiler 1 Tons SO2 emitted	ash as rec.	Boiler 1 Nat Gas therm	Boiler 1 Nat Gas (mmft^3)	Boiler 1 Hours	Boiler 1 (mmBtu/hr	Boiler 2 Coal (ton)	Blr 1+2	Boiler 2 Nat Gas th	Boiler 2 Nat Gas (M	Tons SO2 emitted	=39*% S * ton coal/2000 Boiler 2 Boiler 2 Hours	Boiler 2 (mmBtu/hr	stoker coa cl (ug/g)	stoker coal Hg (ug/g)	
January-06	10956	1012	5611	1.26	2.24	137.86227	8.93	0	0	744	165.253	5652	11263	0	0	138.8696	744	166.4605	236	0.06	
February-06	11092	1012	4970	1.19	2.09	115.32885	8.2	0	0	672	164.0692	5155	10125	672	0.066535	119.6218	672	170.1764	181	0.06	
March-06	11308	1012	1720	1.03	1.78	34.5462	7.42	3562	0.351976285	139	279.8527	4916	6636	0	0	98.73786	578	192.3534	113	0.06	
April-06	11080	1012	5249	1.19	2.09	121.803045	8.21	22113	2.185079051	720	161.5526	1646	6895	6118	0.605743	38.19543	278	131.2063	121	0.06	
May-06	11121	1012	6139	1.08	1.59	129.28734	8.13	18292	1.807509881	744	183.5264	6417	12556	0	0	135.142	744	191.8373	165	0.06	
June-06	11370	1012	5427	0.94	1.61	99.47691	7.99	27995	2.766304348	720	171.4028	5685	11112	16426	1.626337	104.2061	720	179.5513	120	0.04	
July-06	11202	1012	5430	0.95	1.65	100.59075	7.62	5039	0.497924901	744	163.5131	5347	10777	0	0	99.05318	744	161.0137	105	0.04	
August-06	11101	1012	5789	0.92	1.62	103.85466	7.82	1138	0.112450593	744	172.7519	5768	11557	0	0	103.4779	744	172.1252	89	0.04	
September-06	11042	1012	4793	0.97	1.71	90.659595	7.99	470	0.046442688	720	147.012	4771	9564	0	0	90.24347	720	146.3372		0.04	
October-06	11343	1012	1742	0.88	1.51	29.89272	7.97	3207	0.316897233	269	146.9108	4052	5794	141	0.01396	69.53232	650	141.421		0.04	
November-06	10997	1012	3484	0.92	1.63	62.50296	7.3	4125	0.407608696	540	141.902	4239	7723	3102	0.307129	76.04766	663	140.6223		0.05	
December-06	11142	1012	5704	0.95	1.66	105.6666	7.94	4577	0.452272727	744	170.844	5690	11394	0	0	105.4073	744	170.4247		0.05	
	11146.16667		56058	1.023333333		1131.4719	7.96	90518	8.944466403	7500		59338	115396	26459	2.619703	1178.535	8001		119.75	0.049090909	4.4E-06 lb/mmBtu Hg
						1089.95438										1153.729					HF EF=

	HCl TPY	Hg TPY	Hg TPY (control)	0.15 lb/ton coal
Blr 1	6.528792	0.002879		4.20435
Blr 2	6.910797	0.003047		4.45035

2006 NOx Blr 1	469094.1	lbs	234.55	tons
2006 NOx Blr 2	491477.9	lbs	245.74	tons
2006 PM Blr 1	**587341.9023**	**lbs**	**293.67**	**tons**
2006 PM Blr 2	**92594.77327**	**lbs**	**46.30**	**tons**

	Blr 1	%annual	Blr 2	%annual
1st Q Coal	12301	21.94334	15723	26.49735414
2nd Q Coal	16815	29.99572	13748	23.16896424
3rd Q coal	16012	28.56327	15886	26.77205164
4th Q coal	10930	19.49766	13981	23.56162998

2006 Boiler #5

Date	Coal Heat Value (Btu/lb)	% Sulfur b weight in C	From CEMS SO2 lb/Mbtu 30-day roll ave	SO2 tons emitted	ash conter as receive	Nat gas (therms)	Nat gas MMft^3	Boiler 5 Coal (ton)	Boiler 5 Hours	Boiler 5 (mmBtu/hr)	Boiler 5 limestone(	Boiler 5 Cl (ug/g)	Boiler 5 Hg (ug/g)
Jan-06	10783	2.46	0.323	22.94192158	10.51	0	0	6587	744	190.934465	1022	139	0.09
Feb-06	10839	2.27	0.332	23.12426945	9.95	0	0	6426	672	207.295875	1091	136	0.09
Mar-06	10813	2.19	0.326	27.36839503	10.22	0	0	7764	744	225.677774	1302	92	0.08
Apr-06	10925	2.16	0.312	17.844021	9.86	0	0	5235	516	221.675872	859	64	0.07
May-06						0	0	0	0	#DIV/0!	25		
Jun-06	10921	2.09	0.363	3.468782625	10.93	5849	0.577964	875	120	159.264583	134	68	0.08
Jul-06	10924	2.16	0.268	15.28516667	10.35	704	0.069565	5221	721	158.20861	991	156	0.08
Aug-06	10823	2.38	0.266	16.62575145	10.61	0	0	5775	744	168.018347	1063	187	0.09
Sep-06	10851	2.65	0.268	6.749625828	10.8	0	0	2321	355	141.888287	386	129	0.1
Oct-06	10992	2.54	0.276	15.39952819	9.76	0	0	5076	611	182.636308	1003		0.1
Nov-06	10861	2.56	0.348	21.77821654	10.06	0	0	5762	720	173.836339	981		0.1
Dec-06	10838	2.72	0.418	28.08323052	9.89	0	0	6199	744	180.604199	939		0.11
totals/averages	10870	2.38	0.318181818	198.6689089	10.26727		0.64753	57241	6691		9796	121.375	0.09

2006 CO blr 5	60.97654766	tons		
2006 NOx blr 5	143108.6	lbs	71.5543	tons
2006 PM blr 5	1.24441934	tons		

	HCl TPY	Hg TPY	HF EF= 0.15 lb/ton coal
	6.757035028	0.005152	4.293075
controlled:	0.675703503	0.000515	0.429308

Actual stack test shows 0.0018-0.0014 lb HF/ton coal
Mostardi Platt 2001

	BLR 5	%annual
1st Q Coal	20777	36.29741
2nd Q Coal	6110	10.67417
3rd Q coal	13317	23.26479
4th Q coal	17037	29.76363

Year	Date	Boiler 1	1 Rolling 24-mo	1 Rolling Annual	Boiler 2	1 and 2 Total	1 and 2 Rolling 24-mo	1 and 2 Rolling Annual
2003	January	12352.4			14372.9	26725.3		
2003	February	11343.5			13579.6	24923.1		
2003	March	13216.6			15476.1	28692.7		
2003	April	10465.145			9186.785	19651.93		
2003	May	11232.08			3335.3	14567.38		
2003	June	9197.2			10352.6	19549.8		
2003	July	10155.2			11553	21708.2		
2003	August	10807.6			11826.3	22633.9		
2003	September	11207.9			10345.24	21553.14		
2003	October	4715.117			11080.4	15795.517		
2003	November	6420.064			12141.4	18561.464		
2003	December	11971.8			12199.3	24171.1		
2004	January	11488.93			12852.9	24341.83		
2004	February	11462.4			11489.1	22951.5		
2004	March	9428.667			12155.881	21584.548		
2004	April	14158.7			12564.056	26722.756		
2004	May	12274.512			3687.236	15961.748		
2004	June	10799.7			11096.5	21896.2		
2004	July	11649.7			11759.5	23409.2		
2004	August	11861.3			11114.167	22975.467		
2004	September	13106.3			13451.4	26557.7		
2004	October	10364.352			12738.15	23102.502		
2004	November	4640.96			14280.4	18921.36		
2004	December	13377.4	257697.53	128848.76	13679.4	27056.8	534015.142	267007.571
2005	January	13893.6	259238.73	129619.36	14251.6	28145.2	535435.042	267717.521
2005	February	12054.1	259949.33	129974.66	12958.9	25013	535524.942	267762.471
2005	March	14385.1	261117.83	130558.91	15777.7	30162.8	536995.042	268497.521
2005	April	12327.2	262979.88	131489.94	3051.218	15378.418	532721.53	266360.765
2005	May	11932.7	263680.5	131840.25	1491.675	13424.375	531578.525	265789.2625
2005	June	11692	266175.3	133087.65	11579.5	23271.5	535300.225	267650.1125
2005	July	12407.3	268427.4	134213.7	12619.5	25026.8	538618.825	269309.4125
2005	August	12548.1	270167.9	135083.95	12860.9	25409	541393.925	270696.9625
2005	September	8823.817	267783.82	133891.91	11996.6	20820.417	540661.202	270330.601
2005	October	6569.846	269638.55	134819.27	14030.2	20600.046	545465.731	272732.8655
2005	November	9180.575	272399.06	136199.53	11012.62	20193.195	547097.462	273548.731
2005	December	12207.845	272635.1	136317.55	13354.555	25562.4	548488.762	274244.381
2006	January	10905.9	272052.07	136026.04	12290.4	23196.3	547343.232	273671.616
2006	February	10185.1	270774.77	135387.39	11486.1	21671.2	546062.932	273031.466
2006	March	3925.729	265271.84	132635.92	10790.6	14716.329	539194.713	269597.3565
2006	April	13514.8	264627.94	132313.97	4796.774	18311.574	530783.531	265391.7655
2006	May	12356.7	264710.12	132355.06	13539.7	25896.4	540718.183	270359.0915
2006	June	11958.5	265868.92	132934.46	12588.187	24546.687	543368.67	271684.335
2006	July	11476.2	265695.42	132847.71	12405.4	23881.6	543841.07	271920.535
2006	August	11479.5	265313.62	132656.81	12014.1	23493.6	544359.203	272179.6015
2006	September	11042.7	263250.02	131625.01	11264.6	22307.3	540108.803	270054.4015
2006	October	3904.5	256790.17	128395.09	9058.998	12963.498	529969.799	264984.8995
2006	November	8123.972	260273.18	130136.59	9212.71	17336.682	528385.121	264192.5605
2006	December	13056.4	259952.18	129976.09	12479.8	25536.2	526864.521	263432.2605
2007	January	14628.316	260686.9	130343.45	13659.415	28287.731	527007.052	263503.526
2007	February	12606.156	261238.96	130619.48	12898.508	25504.664	527498.716	263749.358
2007	March	15140.1	261993.96	130996.98	11413.381	26553.481	523889.397	261944.6985

2007 April	14407.1	264073.86	132036.93	0	14407.1	522918.079	261459.0395
2007 May	9883.193	262024.35	131012.17	6699.54	16582.733	526076.437	263038.2185
2007 June	12367.811	262700.16	131350.08	12458.304	24826.115	527631.052	263815.526
2007 July	2804.179	253097.04	126548.52	7556.96	10361.139	512965.391	256482.6955
2007 August	2567.341	243116.28	121558.14	11305.207	13872.548	501428.939	250714.4695
2007 September	10353.588	244646.05	122323.03	10138.586	20492.174	501100.696	250550.348
2007 October	16130.8	254207.01	127103.5	0	16130.8	496631.45	248315.725
2007 November	15961.8	260988.23	130494.12	0	15961.8	492400.055	246200.0275
2007 December	16440.022	265220.41	132610.2	0	16440.022	483277.677	241638.8385
2008 January	19656.094	273970.6	136985.3	0	19656.094	479737.471	239868.7355
2008 February	18506.4	282291.9	141145.95	0	18506.4	476572.671	238286.3355
2008 March	16545.4	294911.57	147455.79	16689.676	33235.076	495091.418	247545.709
2008 April	8022.258	289419.03	144709.52	16475.6	24497.858	501277.702	250638.851
2008 May	8011.917	285074.25	142537.12	13934.6	21946.517	497327.819	248663.9095
2008 June	13474.2	286589.95	143294.97	15319.2	28793.4	501574.532	250787.266
2008 July	13137.8	288251.55	144125.77	15685	28822.8	506515.732	253257.866
2008 August	12482.9	289254.95	144627.47	14892.5	27375.4	510397.532	255198.766
2008 September	13476.015	291688.26	145844.13	14823.2	28299.215	516389.447	258194.7235
2008 October	13887.1	301670.86	150835.43	8533.525	22420.625	525846.574	262923.287
2008 November	10052.024	303598.91	151799.46	10224.051	20276.075	528785.967	264392.9835
2008 December	14590.5	305133.01	152566.51	15729.2	30319.7	533569.467	266784.7335
2009 January	13509.3	304014	152007	15587.9	29097.2	534378.936	267189.468
2009 February	10441.4	301849.24	150924.62	12980.4	23421.8	532296.072	266148.036
2009 March	13032.6	299741.74	149870.87	14791.3	27823.9	533566.491	266783.2455
2009 April	2963.048	288297.69	144148.85	13631.3	16594.348	535753.739	267876.8695
2009 May	4472.687	282887.18	141443.59	10731.511	15204.198	534375.204	267187.602
2009 June	11513.1	282032.47	141016.24	12023.9	23537	533086.089	266543.0445
2009 July	10601.2	289829.49	144914.75	11987.1	22588.3	545313.25	272656.625
2009 August	11544.9	298807.05	149403.53	12871.9	24416.8	555857.502	277928.751
2009 September	11503.5	299956.97	149978.48	10675	22178.5	557543.828	278771.914
2009 October	11418.7	295244.87	147622.43	6313.063	17731.763	559144.791	279572.3955
2009 November	11594.7	290877.77	145438.88	7488.62	19083.32	562266.311	281133.1555
2009 December	14141.4	288579.14	144289.57	14755.272	28896.672	574722.961	287361.4805
2010 January	13968.9	282891.95	141445.97	16134.2	30103.1	585169.967	292584.9835
2010 February	12217.2	276602.75	138301.37	14324.9	26542.1	593205.667	296602.8335
2010 March	12596	272653.35	136326.67	14848.5	27444.5	587415.091	293707.5455
2010 April	3534.494	268165.59	134082.79	9886.19	13420.684	576337.917	288168.9585
2010 May	11378.1	271531.77	135765.88	4312.866	15690.966	570082.366	285041.183
2010 June	11346.1	269403.67	134701.83	13543.6	24889.7	566178.666	283089.333
2010 July	12100.2	268366.07	134183.03	14279.5	26379.7	563735.566	281867.783
2010 August	12745.5	268628.67	134314.33	14675.6	27421.1	563781.266	281890.633
2010 September	5978.109	261130.76	130565.38	14123.8	20101.909	555583.96	277791.98
2010 October	12139.7	259383.36	129691.68	12173.056	24312.756	557476.091	278738.0455
2010 November	14199.9	263531.24	131765.62	5409.597	19609.497	556809.513	278404.7565
2010 December	13828.1	262768.84	131384.42	14318.723	28146.823	554636.636	277318.318
2011 January	13876.4	263135.94	131567.97	15970.6	29847	555386.436	277693.218
2011 February	10188.4	262882.94	131441.47	13373.2	23561.6	555526.236	277763.118
2011 March	12116.2	261966.54	130983.27	15459.1	27575.3	555277.636	277638.818
2011 April	2923.1	261926.59	130963.3	12365	15288.1	553971.388	276985.694
2011 May	13330.4	270784.3	135392.15	179.2	13509.6	552276.79	276138.395
2011 June	12381.3	271652.5	135826.25	12721.5	25102.8	553842.59	276921.295
2011 July	13680.6	274731.9	137365.95	14707.8	28388.4	559642.69	279821.345
2011 August	12791.5	275978.5	137989.25	13838.8	26630.3	561856.19	280928.095
2011 September	10810.3	275285.3	137642.65	7155.2	17965.5	557643.19	278821.595
2011 October	4016.3	267882.9	133941.45	10206.1	14222.4	554133.827	277066.9135
2011 November	4.6	256292.8	128146.4	12999	13003.6	548054.107	274027.0535
2011 December	6956.3	249107.7	124553.85	15082	22038.3	541195.735	270597.8675

Purdue University Unit 1
Monthly CEM Emissions Data

Year	Month	CO_2 (tons)	NOx (tons)	SO_2 (tons)
2003	January	12352.4	---	---
2003	February	11343.5	---	---
2003	March	13216.6	---	---
2003	April	10465.1	---	---
2003	May	11232.1	---	---
2003	June	9197.2	---	---
2003	July	10155.2	---	---
2003	August	10807.6	---	---
2003	September	11207.9	---	---
2003	October	4715.1	---	---
2003	November	6420.1	---	---
2003	December	11971.8	---	---
2004	January	11488.9	---	---
2004	February	11462.4	---	---
2004	March	9428.7	---	---
2004	April	14158.7	---	---
2004	May	12274.5	---	---
2004	June	10799.7	---	---
2004	July	11649.7	---	---
2004	August	11861.3	---	---
2004	September	13106.3	---	---
2004	October	10364.4	---	---
2004	November	4641.0	---	---
2004	December	13377.4	---	---
2005	January	13893.6	---	---
2005	February	12054.1	---	---
2005	March	14385.1	---	---
2005	April	12327.2	---	---
2005	May	11932.7	---	---
2005	June	11692.0	---	---
2005	July	12407.3	---	---
2005	August	12548.1	---	---
2005	September	8823.8	---	---
2005	October	6569.8	---	---
2005	November	9180.6	---	---
2005	December	12207.8	---	---
2006	January	10905.9	---	---
2006	February	10185.1	---	---
2006	March	3925.7	---	---
2006	April	13514.8	---	---
2006	May	12356.7	---	---

2006	June	11958.5	---	99.5
2006	July	11476.2	---	91.8
2006	August	11479.5	---	92.5
2006	September	11042.7	---	88.6
2006	October	3904.5	---	30.7
2006	November	8124.0	---	60.9
2006	December	13056.4	---	104.6
2007	January	14628.3	---	120.9
2007	February	12606.2	---	107.6
2007	March	15140.1	---	119.7
2007	April	14407.1	---	112.3
2007	May	9883.2	---	75.3
2007	June	12367.8	---	121.8
2007	July	2804.2	---	28.5
2007	August	2567.3	---	25.5
2007	September	10353.6	---	99.3
2007	October	16130.8	---	151.3
2007	November	15961.8	---	133.3
2007	December	16440.0	---	139
2008	January	19656.1	---	155.9
2008	February	18506.4	---	145.5
2008	March	16545.4	---	123.9
2008	April	8022.3	---	62.5
2008	May	8011.9	---	72.2
2008	June	13474.2	---	127.6
2008	July	13137.8	---	133.2
2008	August	12482.9	---	125.6
2008	September	13476.0	---	124.0
2008	October	13887.1	---	125.6
2008	November	10052.0	---	87.5
2008	December	14590.5	---	129.7
2009	January	13509.3	---	118.6
2009	February	10441.4	---	83.1
2009	March	13032.6	---	96.7
2009	April	2963.0	---	28.0
2009	May	4472.7	---	31.1
2009	June	11513.1	---	82.2
2009	July	10601.2	---	80.8
2009	August	11544.9	---	74.0
2009	September	11503.5	---	62.5
2009	October	11418.7	---	62.1
2009	November	11594.7	---	71.8
2009	December	14141.4	---	103.2
2010	January	13968.9	---	94.3
2010	February	12217.2	---	94.7
2010	March	12596.0	---	104.0

2010	April	3534.5	6.2	26.7
2010	May	11378.1	22.0	86.3
2010	June	11346.1	21.6	62.1
2010	July	12100.2	24.0	46.2
2010	August	12745.5	25.7	74.0
2010	September	5978.1	11.0	19.3
2010	October	12139.7	27.3	68.2
2010	November	14199.9	32.3	160.1
2010	December	13828.1	28.7	109.9
2011	January	13876.4	30.1	93.7
2011	February	10188.4	20.5	98.6
2011	March	12116.2	25.4	137.5
2011	April	2923.1	6.1	33.4
2011	May	13330.4	30.0	137.6
2011	June	12381.3	26.7	147.9
2011	July	13680.6	28.1	150.9
2011	August	12791.5	26.7	144.1
2011	September	10810.3	20.6	117.3
2011	October	4016.3	7.8	39.6
2011	November	4.6	0.0	0.0
2011	December	6956.3	12.8	67.1

QDS/PGB 03/27/12

BLR 1	Coal use (tons)
Apr-10	1,664
May-10	4,402
Jun-10	5,202
Jul-10	5,647
Aug-10	5,216
Sep-10	3,285
Oct-10	4,992
Nov-10	6,870
Dec-10	6,265
Jan-11	6,329
Feb-11	5,461
Mar-11	7,030
Apr-11	1,096
May-11	7,099
Jun-11	5,320
Jul-11	5,435
Aug-11	5,354
Sep-11	4,551
Oct-11	1,928
Nov-11	233
Dec-11	2,873

Emission Statement Data

Year	Process	CO2e (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	CO (tpy)	Lead (tpy)	Beryllium (tpy)	Mercury (tpy)	Hexane (tpy)	Total (tpy)
										7439-92-1	7440-41-7	7439-97-6		
2007	Boiler 1		327.02	292.93	182.3	1209	282.72	1.56	155.92	0.0075		0.0005		
2008	Boiler 1		455.7	317.63	197.67	1413.12	361.64	1.7147	171.4725	0.0083		0.002		
2009	Boiler 1		356.88	248.76	154.81	894.13	356.88	1.3361	133.61	0.0064		0.0023		
2010	Boiler 1		264.81	275.265	171.31	945.07	277.9	1.4736	147.3625	0.0071		0.0026		
average			406.29	283.195	176.24	1153.625	359.26	1.5254	152.5413	0.00735		0.00215		
2007	Boiler 2		31.4	9.76	3.87	805	175.81	1.0053	100.53	0.0048		0.0035		
2008	Boiler 2		17.5	13.776	5.4553	1235.77	312.85	1.4182	141.825	0.0068		0.0003		
2009	Boiler 2		17.25	13.5298	5.3587	1051.7	343.7	1.3932	139.315	0.0067		0.0024		
2010	Boiler 2		159.86	13.6153	5.3926	919.52	303.5	1.402	140.195	0.0068		0.0025		
average			17.375	13.6529	5.407	1143.735	328.275	1.4057	140.57	0.00675		0.00135		

Limited Potential to Emit for Boiler 7, New CT/HRSG, and Boiler 2

Process	CO2e (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	CO (tpy)	Lead (tpy)	Beryllium (tpy)	Mercury (tpy)	Hexane (tpy)	Total (tpy)
Boiler 7 (NG)	145,717.34	9.46	9.46	9.46	0.75	62.26	6.85	104.60	6.23E-04	1.49E-05	3.24E-04	2.24	2.35
New CT/HRSG	81,513.90	40.59	40.59	40.59	0.10	66.04	5.37	73.34					
Boiler 2 (NG)	158,279.18	10.28	10.28	10.28	0.81	206.96	7.44	68.99	6.76E-04	1.62E-05	3.52E-04	2.43	2.55
Total Future Potential	**385,510.43**	**60.34**	**60.34**	**60.34**	**1.66**	**335.26**	**19.66**	**246.93**	**0.00**	**0.00003**	**0.00**	**4.68**	**4.90**
PSD Major Modification Threshold (tpy)	**75,000**	**25**	**15**	**10**	**40**	**40**	**40**	**100**	**0.6**	**0.00040**	**0.1**	**NA**	**NA**
Triggers PSD Applicability Analysis? (Yes or No)	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**No**	**Yes**	**No**	**No**	**No**		

Emissions Netting Analysis

Emissions	CO2e (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	CO (tpy)	Lead (tpy)	Beryllium (tpy)	Mercury (tpy)	Hexane (tpy)	Total (tpy)
Boiler 7 & 2 and CT/HRSG	385,510.43	60.34	60.34	60.34	1.66	335.26	19.66	246.93	0.00	0.00	0.00	4.68	4.90
Contemporaneous Increases													
Contemp Nat Gas Em Gens	22.05	0.001921	0.001921	0.001921	0.000113	0.784352	0.0226847	0.107079	0	0	0	0.000213	0.013689
Contemp Nat Gas Boilers	4,445	0.288692	0.288692	0.288692	0.022791	3.798576	0.2089217	3.190804	1.90E-05	4.56E-07	9.88E-06		
Contemp Diesel Em Gen < 600 hp	1658.30	3.17	3.17	3.17	2.96	44.70	3.56	9.63					0.005779
Contemp Diesel Em Gen > 600 hp	173.90	0.07	0.06	0.06	0.54	3.42	0.01	0.91					0.00168
Contemp Poultry Incinerator	284.69	0.13	0.15	0.15	1.22	0.80	0.05	0.09					
Contemporaneous Decreases (Boiler 1 Removal)	152,567	420.11	306.10	190.50	1390.19	353.44	1.5254	164.15	0.00735	0	0.00215	0	0
Net Emissions Increase	232,943.92	-359.77	-245.76	-130.16	-1,388.53	34.52	18.13	82.78	-0.01	0.00	0.00	4.68	4.90
PSD Major Modification Threshold (tpy)	**75,000**	**25**	**15**	**10**	**40**	**40**	**40**	**100**	**0.6**	**0.00040**	**0.1**	**NA**	**NA**
Triggers PSD after Netting?	**Yes**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**		

Emergency Engine Hours Limit = 500 hours

Table 1 - Estimated CT/HRSG Emissions

Burns & Mac - Purdue

(1) Gas Fuel TAURUS with fired HRSG		Per Unit	Plant Total
Ambient Temperature	°F		
Fuel Type		Gas	
Assumed Fuel Sulphur Content	lb/MMBTU (HHV)	0.00	
Heat Input to Gas Turbine (Max at -9.9 deg F)	MMBtu/hr (HHV)	84.2	84.2
Heat Input from Duct Firing	MMBtu/hr (HHV)	75.0	75.0
NOx from Gas Turbine	lb/MMBTU (LHV)	0.10	
Additive NOx from Duct Firing	lb/MMBTU (HHV)	0.10	
CO from Gas Turbine	lb/MMBTU (LHV)	0.122	
Additive CO from Duct Firing	lb/MMBTU (HHV)	0.100	
UHC as CH4 from Gas Turbine	lb/MMBTU (LHV)	0.035	
Additive UHC as CH4 from Duct Firing	lb/MMBTU (HHV)	0.020	
$PM_{10}/PM_{2.5}$ Particulates from Gas Turbine	lb/MMBTU (HHV)	0.021	
Additive PM-10 Particulates from Duct Firing	lb/MMBTU (HHV)	0.100	
Gas Turbine Exhaust Emissions			
NOx	lb/hr	7.6	7.6
CO	lb/hr	9.2	9.2
UHC	lb/hr	2.7	2.7
$PM_{10}/PM_{2.5}$	lb/hr	1.8	1.8
SO_2	lb/hr	0.0	0.0
Duct Burner Exhaust Emissions			
NOx	lb/hr	7.5	7.5
CO	lb/hr	7.5	7.5
UHC	lb/hr	1.5	1.5
$PM_{10}/PM_{2.5}$	lb/hr	7.5	7.5
SO_2	lb/hr	0.0	0.0
Exhaust Emissions At Stack			
NOx	lb/MMBtu, HHV	0.095	
	lb/hr	15.1	15.1
	tons/year	66.0	66.0
CO	lb/MMBtu, HHV	0.105	
	lb/hr	16.7	16.7
	tons/year	73.3	73.3
UHC	lb/MMBtu, HHV	0.026	
	lb/hr	4.2	4.2
	tons/year	18.2	18.2
VOC	lb/MMBtu, HHV	0.008	
	lb/hr	1.2	1.2
	tons/year	5.4	5.4
$PM_{10}/PM_{2.5}$	lb/hr	9.3	9.3
	lb/MMBtu, HHV	0.058	
	tons/year	40.6	40.6
SO_2	lb/hr	0.02	0.02
	lb/MMBtu, HHV	0.00014	
	tons/year	0.1	0.1
Greenhouse Gas Emissions	lbs of CO2/MMBtu (HHV)	116.9	

General Notes
SO2 emissions depend upon the fuel's sulfur content. The SO2 estimate is based upon the assumption of 100% conversion of fuel sulphur to SO2, using assumed

Turbine Emissions Notes:

Values given above are for 8760 hours/year operation.

The table below gives the load ranges to which the turbine emissions listed above apply

Pollutant	Load Range
NOx	50 to 100%
CO	50 to 100%
UHC	50 to 100%

Boiler 2 Potential to Emit Calculations

Heat Input Capacity = 315 MMBtu/hr
Steam Output = 215,000 lb/hr boiler
Heat Input = 315,000,000 mmBtu/hr

Fuel Consumption = Natural Gas
Natural Gas - Heat content = 1020 Btu/cu ft
Maximum Fuel Feed Rate = 308,824 cf/hr
2,705 MMCF/yr

Pollutant	Maximum rate MMCF/hr	Emission Factor lb/MMCF	Maximum Uncontrolled Emission lb/hr	Maximum Uncontrolled Emission lb/MMBtu	Maximum Uncontrolled Emissions tpy	Carbon Dioxide Equivalents	Combined CO2e (tpy)
PM (filterable)	0.309	1.9	0.5868	0.0019	2.57		
PM_{10} (filterable + condensable)	0.309	7.6	2.3471	0.0075	10.28		
$PM_{2.5}$ (filterable + condensable)	0.309	7.6	2.3471	0.0075	10.28		
SO_2	0.309	0.6	0.1853	0.0006	0.81		
NOx	0.309	153	47.2500	0.1500	206.96		
VOC	0.309	5.5	1.6985	0.0054	7.44		
CO*	0.309	51	15.75	0.0500	68.99		
CO_2	0.309	116,900	36101.47	114.6078	158,124.44	**158,124.44**	
CH_4	0.309	2.2	0.68	0.0022	2.98	**62.49**	**158,279.18**
N_2O	0.309	0.22	0.07	0.0002	0.30	**92.25**	
Hazardous Air Pollutants							
Lead	0.309	5.00E-04	1.54E-04	4.90E-07	6.76E-04		
Beryllium	0.309	1.20E-05	3.71E-06	1.18E-08	1.62E-05		
Mercury	0.309	2.60E-04	8.03E-05	2.55E-07	3.52E-04		
Arsenic	0.309	2.00E-04	6.18E-05	1.96E-07	2.71E-04		
Chromium	0.309	1.40E-03	4.32E-04	1.37E-06	1.89E-03		
Cobalt	0.309	8.40E-05	2.59E-05	8.24E-08	1.14E-04		
Manganese	0.309	3.80E-04	1.17E-04	3.73E-07	5.14E-04		
Nickel	0.309	2.10E-03	6.49E-04	2.06E-06	2.84E-03		
Selenium	0.309	2.40E-05	7.41E-06	2.35E-08	3.25E-05		
2-Methylnaphthalene	0.309	2.40E-05	7.41E-06	2.35E-08	3.25E-05		
3-Methylchloroanthrene	0.309	1.80E-06	5.56E-07	1.76E-09	2.43E-06		
7,12-Dimethylbenz(a)anthracene	0.309	1.60E-05	4.94E-06	1.57E-08	2.16E-05		
Acenapthene	0.309	1.60E-06	4.94E-07	1.57E-09	2.16E-06		
Acenaphthylene	0.309	1.80E-06	5.56E-07	1.76E-09	2.43E-06		
Benzene	0.309	2.10E-03	6.49E-04	2.06E-06	2.84E-03		
Benzo(a)pyrene	0.309	1.20E-06	3.71E-07	1.18E-09	1.62E-06		
Benzo(b)fluoranthene	0.309	1.80E-06	5.56E-07	1.76E-09	2.43E-06		
Benzo(k)fluoranthene	0.309	1.80E-06	5.56E-07	1.76E-09	2.43E-06		
Chrysene	0.309	1.80E-06	5.56E-07	1.76E-09	2.43E-06		
Dibenzo(a,h)anthracene	0.309	1.20E-06	3.71E-07	1.18E-09	1.62E-06		
Dichlorobenzene	0.309	1.20E-03	3.71E-04	1.18E-06	1.62E-03		
Fluoranthene	0.309	3.00E-06	9.26E-07	2.94E-09	4.06E-06		
Fluorene	0.309	2.80E-06	8.65E-07	2.75E-09	3.79E-06		
Formaldehyde	0.309	0.08	0.02	7.35E-05	0.10		
Hexane	0.309	1.80	0.56	1.76E-03	2.43		
Indeno(1,2,3-cd)pyrene	0.309	1.80E-06	5.56E-07	1.76E-09	2.43E-06		
Naphthalene	0.309	6.10E-04	1.88E-04	5.98E-07	8.25E-04		
Phenanathrene	0.309	1.70E-05	5.25E-06	1.67E-08	2.30E-05		
Pyrene	0.309	5.00E-06	1.54E-06	4.90E-09	6.76E-06		
Toluene	0.309	3.40E-03	1.05E-03	3.33E-06	4.60E-03		
Total HAP			0.58		**2.55**		

* Emission Factor for CO assumed to be 0.05 lb/mmBtu

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Robin Mills Ridgway
Purdue University
HMMT, 201 Ahlers Dr
West Lafayette, IN 47906-5991

DATE: March 27, 2013

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

SUBJECT: Final Decision
Title V - Significant Permit Modification
157 - 32275 - 00012

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:
Robert E McMains, VP - Physical Facilities
David Jordan Environmental Resources Management
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 11/30/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

March 27, 2013

TO: West Lafayette Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Purdue University
Permit Number: 157 - 32275 - 00012

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 11/30/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

TO: Interested Parties / Applicant

DATE: March 27, 2013

RE: Purdue University / 157 - 32275 - 00012

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

In order to conserve paper and reduce postage costs, IDEM's Office of Air Quality is now sending many permit decisions on CDs in Adobe PDF format. The enclosed CD contains information regarding the company named above.

This permit is also available on the IDEM website at:
http://www.in.gov/ai/appfiles/idem-caats/

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

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

Please Note: *If you feel you have received this information in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV.*

Enclosures
CD Memo.dot 11/14/08

Mail Code 61-53

IDEM Staff	LPOGOST 3/27/2013 Purdue University 157 - 32275 - 00012 final)		AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	► Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee / Remarks
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2		Robert E McMains VP - Physical Facilities Purdue University 401 S Grant St, 1662 Freehafer West Lafayette IN 47907-4024 *(RO CAATS)*									
3		Tippecanoe County Commissioners 20 N 3rd St, County Office Building Lafayette IN 47901 *(Local Official)*									
4		Tippecanoe County Health Department 20 N. 3rd St Lafayette IN 47901-1211 *(Health Department)*									
5		Lafayette City Council and Mayors Office 20 North 6th Street Lafayette IN 47901-1411 *(Local Official)*									
6		Ms. Geneva Werner 3212 Longlois Drive Lafayette IN 47904-1718 *(Affected Party)*									
7		Mrs. Phyllis Owens 3600 Cypress Lane Lafayette IN 47905 *(Affected Party)*									
8		Mr. Jerry White 4317 Amesbury Drive West Lafayette IN 47906 *(Affected Party)*									
9		West Lafayette Public Library 208 W Columbus St West Lafayette IN 47906-3096 *(Library)*									
10		Ms. Rose Filley 5839 Lookout Drive West Lafayette IN 47906 *(Affected Party)*									
11		Mr. William Cramer 128 Seminole Drive West Lafayette IN 47906 *(Affected Party)*									
12		Mr. Robert Kelley 2555 S 30th Street Lafayette IN 44909 *(Affected Party)*									
13		David Jordan Environmental Resources Management (ERM) 11350 North Meridian, Suite 320 Carmel IN 46032 (Consultant)									
14		West Lafayette City Council and Mayors Office 609 W. Navajo West Lafayette IN 47906 *(Local Official)*									
15		James Giampietro Sierra Club Environmental Law Program 85 Second St 2nd Floor San Francisco CA 94105 *(Affected Party)*									

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