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

**Michael R. Pence**
*Governor*

**Thomas W. Easterly**
*Commissioner*

| | |
|---|---|
| To: | Interested Parties |
| Date: | May 15, 2014 |
| From: | Matthew Stuckey, Chief<br>Permits Branch<br>Office of Air Quality |
| Source Name: | Purdue University |
| Permit Level: | Title V - Significant Source Modification |
| Permit Number: | 157 - 34219 - 00012 |
| Source Location: | 401 S. Grant Street, Freehafer Hall of Administrative Services, West Lafayette, Indiana |
| Type of Action Taken: | Modification at an existing source |

# Notice of Decision: Approval - Effective Immediately

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

The final decision is available on the IDEM website at: http://www.in.gov/apps/idem/caats/
To view the document, select Search option 3, then enter permit 34219.

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

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

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

*(continues on next page)*

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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

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*Commissioner*

May 15, 2014

Robin Mills Ridgway
Director of Environmental, Health, and Safety Regulation Compliance
HMMT, 201 Ahlers Drive
West Lafayette, IN 47906

Re: 157-34219-00012
Significant Source Modification

Dear Robin Mills Ridgway:

Purdue University was issued Part 70 Operating Permit Renewal No. T157-27313-00012 on August 27, 2010 for stationary boilers and other support facilities for the educational services operation located at 401 S. Grant Street, Freehafer Hall of Administrative Services, West Lafayette, IN 47907. An application to modify the source was received on February 21, 2014. Pursuant to the provisions of 326 IAC 2-7-10.5, a Significant Source Modification is hereby approved as described in the attached Technical Support Document.

Pursuant to 326 IAC 2-7-10.5, the following emission unit is approved for construction at the source:

(a) One (1) temporary portable bulk limestone storage bin, permitted in 2014, identified as LS2-T, with a maximum capacity of 25,492 tons of limestone per year, using cartridge filter (BVLI5) as control, and exhausting to stack BVLI5.

The following construction conditions are applicable to the proposed modification:

General Construction Conditions

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

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

Effective Date of the Permit

3. Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

Commenced Construction

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

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

Approval to Construct

6. Pursuant to 326 IAC 2-7-10.5(h)(2), this Significant Source Modification authorizes the construction of the new emission unit(s), when the Significant Source Modification has been issued.

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

Pursuant to 326 IAC 2-7-12, operation of the new emission unit(s) is not approved until the Significant Permit Modification has been issued. Operating conditions shall be incorporated into the Part 70 Operating Permit as a Significant Permit Modification in accordance with 326 IAC 2-7-10.5(m)(2) and 326 IAC 2-7-12 (Permit Modification).

A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. 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, refer to the IDEM's Permit Guide on the Internet at: www.idem.in.gov

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 Deena Patton of my staff, OAQ, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Deena Patton or extension 4-5400 or dial (317) 234-5400.

Sincerely,

Tripurari Sinha

Tripurari P. Sinha, Ph. D., Section Chief
Permits Branch
Office of Air Quality

Attachments: Significant Source Modification and Technical Support Document

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

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*Commissioner*

# Significant Source Modification to a Part 70 Source

## 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 construct subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

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

| Significant Source Modification No.: 157-34219-00012 | |
|---|---|
| Issued by:<br>Tripurari Sinha<br>Tripurari P. Sinha, Ph.D, Branch Chief<br>Permits Branch<br>Office of Air Quality | Issuance Date:<br>May 15, 2014 |

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**E.3 NEW SOURCE PERFORMANCE STANDARDS - Coal Preparation Plants**

E.3.1 General Provisions Relating to NSPS [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.3.2 Standards of Performance for Coal Preparation Plants [326 IAC 12] [40 CFR 60, Subpart Y]

**E.4 New Source Performance Standards [40 CFR 60, Subpart KKKK]**

E.4.1 General Provisions Relating to New Source Performance Standard [326 IAC 12-1] [40 CFR Part 60, Subpart A]
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**E.5 National Emissions Standard for Hazardous Air Pollutants [40 CFR 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]
E.5.2 National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines [40 CFR Part 63, Subpart YYYY] [326 IAC 20]

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

F.1 Automatic Incorporation of Definitions [326 IAC 24-3-7(e)] [40 CFR 97.323(b)]
F.2 Standard Permit Requirements [326 IAC 24-3-4(a)] [40 CFR 97.306(a)]
F.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-3-4(b)] [40 CFR 97.306(b)]
F.4 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]
F.5 Excess Emissions Requirements [326 IAC 24-3-4(d)] [40 CFR 97.306(d)]
F.6 Record Keeping Requirements [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.306(e)]
F.7 Reporting Requirements [326 IAC 24-3-4(e)] [40 CFR 97.306(e)]
F.8 Liability [326 IAC 24-3-4(f)] [40 CFR 97.306(f)]
F.9 Effect on Other Authorities [326 IAC 24-3-4(g)] [40 CFR 97.306(g)]
F.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-3-6] [40 CFR 97, Subpart BBBB]

**Certification**
**Emergency Occurrence Report**
**Quarterly Reports**
**Quarterly Deviation and Compliance Monitoring Report**

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

**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]**

**Attachment C: Standards of Performance for Coal Preparation Plants [326 IAC 12] [40 CFR Part 60, Subpart Y]**

**Attachment D: New Source Performance Standards for Stationary Combustion Turbines [326 IAC 12] [40 CFR Part 60, Subpart KKKK]**

**Attachment E: National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines [326 IAC 20] [40 CFR Part 63, Subpart YYYY]**

## 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<br>Major, under PSD<br>Major Source, Section 112 of the Clean Air Act<br>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.

**<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 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.

(p) One (1) temporary portable bulk limestone storage bin, permitted in 2014, identified as LS2-T, with a maximum capacity of 25,492 tons of limestone per year, using cartridge filter (BVLI5) as control, and exhausting to stack BVLI5.

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.

(p) One (1) temporary portable bulk limestone storage bin, permitted in 2014, identified as LS2-T, with a maximum capacity of 25,492 tons of limestone per year, using cartridge filter (BVLI5) as control, and exhausting to stack BVLI5.

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]

(a) 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).

(b) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the temporary portable bulk storage bin shall not exceed 8.39 pounds per hour when operating at a process weight rate of 2.91 tons per hour.

The pounds per hour limitations were calculated with the following equation:

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
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.<br><br>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<br>Describe:<br><br>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:** |

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|---|---|
| **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**

**Electronic Code of Federal Regulations**

**Title 40: Protection of Environment**

**40 CFR 60, Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**

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

**§ 60.40b Applicability and delegation of authority.**

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

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

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

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

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

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

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

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

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

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

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

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

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

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

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

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

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

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

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

**§ 60.41b Definitions.**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

*Gross output* means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units,

the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit ( *i.e.* , steam delivered to an industrial process).

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

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

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

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

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

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

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

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

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

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

*Natural gas* means:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) The equipment is attached to a foundation.

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

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

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

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

weight percent sulfur or that, when combusted without $SO_2$ emission control, has a $SO_2$ emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

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

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

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

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

**§ 60.42b Standard for sulfur dioxide (SO2 ).**

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

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

Where:

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

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

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

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

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

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

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential $SO_2$ emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat

input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**§ 60.43b Standard for particulate matter (PM).**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**§ 60.44b Standard for nitrogen oxides (NOX ).**

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

%$P_s$ = Potential $SO_2$ emission rate, percent;

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) The dry basis F factor; and

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

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

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

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

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

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

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit ( *i.e.,* reference method) data and performance test ( *i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/* ) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

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

**§ 60.47b Emission monitoring for sulfur dioxide.**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

z = Fraction of total heat input derived from coal.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**§ 60.49b Reporting and recordkeeping requirements.**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar date;

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

(3) The 30-day average $NO_X$ emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average $NO_X$ emission rates are in excess of the $NO_X$ emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

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

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

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(2) Any affected facility that is subject to the $NO_X$ standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor $NO_X$ emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average $NO_X$ emission rate, as determined under § 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for $NO_X$ under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the $SO_2$ standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average $SO_2$ emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the $SO_2$ control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in $SO_2$ emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which $SO_2$ or diluent ($O_2$ or $CO_2$ ) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

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

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

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

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

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average $SO_2$ emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent ($O_2$ or $CO_2$ ) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

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

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

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

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

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

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

(m) For each affected facility subject to the $SO_2$ standards in § 60.42(b) for which the minimum amount of data required in § 60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

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

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

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

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

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

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

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

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

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

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

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

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

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

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

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

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

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

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

definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

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

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific $NO_X$ standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

*Oxidation zone* is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

*Reducing zone* is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

*Total inlet air* is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The $NO_X$ emission limit shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b(i).

(iii) The monitoring of the $NO_X$ emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific $NO_X$ standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

*Air ratio control damper* is defined as the part of the low $NO_X$ burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

*Flue gas recirculation line* is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The $NO_X$ emission limit shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b.

(iii) The monitoring of the $NO_X$ emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”) and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low $NO_X$ technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring $NO_X$ emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$ and/or $NO_X$ and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific $NO_X$ standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The $NO_X$ emissions shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b.

(ii) The monitoring of the $NO_X$ emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(y) Facility-specific $NO_X$ standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for* $NO_X$ . (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the $NO_X$ emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for* $NO_X$ . (i) The $NO_X$ emissions shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b.

(ii) The monitoring of the $NO_X$ emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

**Attachment B**

**Electronic Code of Federal Regulations**

Title 40: Protection of Environment

**40 CFR 60, Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators**

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 subject to either subpart Da or KKKK of this part is not subject to this subpart.

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

**§ 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.

*Natural gas* means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, 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.

*Wood residue* means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

**§ 60.42 Standard for particulate matter (PM).**

(a) Except as provided under paragraphs (b), (c), (d), and (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:

(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 § 60.42Da(a) of subpart Da of this part.

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential $SO_2$ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of $SO_2$ or PM is exempt from the PM standards specified in paragraph (a) of this section.

[60 FR 65415, Dec. 19, 1995, as amended at 76 FR 3522, Jan. 20, 2011; 74 FR 5077, Jan. 28, 2009; 77 FR 9447, Feb. 16, 2012]

**§ 60.43 Standard for sulfur dioxide (SO2 ).**

(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 $SO_2$ in 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:

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 $NO_2$ in 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:

Where:

$PS_{NO\ X}$ = 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 $NO_X$ does 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 of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring $SO_2$ emissions, $NO_X$ emissions, and either oxygen ($O_2$ ) or carbon dioxide ($CO_2$ ) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS 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 combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential $SO_2$ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of $SO_2$ or PM, COMS for measuring the opacity of emissions and CEMS for measuring $SO_2$

emissions are not required if the owner or operator monitors $SO_2$ emissions 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 $SO_2$ emissions is not required if the owner or operator monitors $SO_2$ emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for $NO_X$ may 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 $NO_X$ emissions is not required. If the initial performance test results show that $NO_X$ emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for $NO_X$ within 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 is not required to and elects not to install any CEMS for either $SO_2$ or $NO_X$ , a CEMS for measuring either $O_2$ or $CO_2$ is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility 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) An owner or operator of an affected facility subject to an opacity standard under § 60.42 that elects to not use 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 by April 29, 2011 or within 45 days after stopping use of an existing COMS, whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements.

(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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; 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 45 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 45 calendar days according to the requirements in § 60.46(b)(3).

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

(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.

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(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 $NO_X$ span values shall be determined as follows:

| | **In parts per million** | |
|---|---|---|
| **Fossil fuel** | **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 $NO_X$ span 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 $O_2$ concentration 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:

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:

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 $4.15 \times 10^4$ M ng/dscm per ppm ($2.59 \times 10^{-9}$ 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 $F_c = 0.532 \times 10^{-17}$ 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 = $2.637 \times 10^{-7}$ dscm/J (9,820 dscf/MMBtu) and $F_c = 0.486 \times 10^{-7}$ scm $CO_2$ /J (1,810 scf $CO_2$ /MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = $2.476 \times 10^{-7}$ dscm/J (9,220 dscf/MMBtu) and $F_c = 0.384 \times 10^{-7}$ scm $CO_2$ /J (1,430 scf $CO_2$ /MMBtu).

(iv) For gaseous fossil fuels, F = $2.347 \times 10^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm $CO_2$ /J (1,040 scf $CO_2$ /MMBtu) for natural gas, $0.322 \times 10^{-7}$ scm $CO_2$ /J (1,200 scf $CO_2$ /MMBtu) for propane, and $0.338 \times 10^{-7}$ scm $CO_2$ /J (1,260 scf $CO_2$ /MMBtu) for butane.

(v) For bark F = $2.589 \times 10^{-7}$ dscm/J (9,640 dscf/MMBtu) and $F_c = 0.500 \times 10^{-7}$ scm $CO_2$ /J (1,840 scf $CO_2$ /MMBtu). For wood residue other than bark F = $2.492 \times 10^{-7}$ dscm/J (9,280 dscf/MMBtu) and $F_c = 0.494 \times 10^{-7}$ 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 = $2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$ 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:

(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:

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 $SO_2$ as 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 $SO_2$ as measured by a CEMS exceed the applicable standard in § 60.43. Facilities complying with the 30-day $SO_2$ standard shall use the most current associated $SO_2$ compliance 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 $NO_X$ as measured by a CEMS exceed the applicable standard in § 60.44. Facilities complying with the 30-day $NO_X$ standard shall use the most current associated $NO_X$ compliance 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; 76 FR 3522, Jan. 20, 2011; 77 FR 9447, Feb. 16, 2012]

**§ 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 $NO_X$ standards in §§ 60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, $SO_2$ , or $NO_X$ shall be computed for each run using the following equation:

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Where:

E = Emission rate of pollutant, ng/J (1b/million Btu);

C = Concentration of pollutant, ng/dscm (1b/dscf);

$\%O_2$ = $O_2$ concentration, 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 $O_2$ concentration (%$O_2$ ). The $O_2$ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the $O_2$ concentration for the run shall be the arithmetic mean of the sample $O_2$ concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the $O_2$ traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 $O_2$ traverse 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 $SO_2$ concentration.

(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 $O_2$ concentration (%$O_2$ ). The $O_2$ sample shall be taken simultaneously with, and at the same point as, the $SO_2$ sample. The $SO_2$ emission rate shall be computed for each pair of $SO_2$ and $O_2$ samples. The $SO_2$ emission 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 $NO_X$ concentration.

(i) The sampling site and location shall be the same as for the $SO_2$ sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each $NO_X$ sample, 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 $O_2$ concentration (%$O_2$ ). The sample shall be taken simultaneously with, and at the same point as, the $NO_X$ sample.

(iii) The $NO_X$ emission rate shall be computed for each pair of $NO_X$ and $O_2$ samples. The $NO_X$ emission 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 $NO_X$ may 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:

Where:

E = Emission rate of pollutant, ng/J (lb/MMBtu);

C = Concentration of pollutant, ng/dscm (lb/dscf);

$\%CO_2$ = $CO_2$ concentration, 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 $CO_2$ concentration 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 $SO_2$ may 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 $SO_2$ emission 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 $O_2$ concentration ($\%O_2$ ) 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

**Electronic Code of Federal Regulations**

**Title 40: Protection of Environment**

**Part 60, Subpart Y—Standards of Performance for Coal Preparation and Processing Plants**

Source: 74 FR 51977, Oct. 8, 2009, unless otherwise noted.

### § 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to affected facilities in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day.

(b) The provisions in § 60.251, § 60.252(a), § 60.253(a), § 60.254(a), § 60.255(a), and § 60.256(a) of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after October 27, 1974, and on or before April 28, 2008: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(c) The provisions in § 60.251, § 60.252(b)(1) and (c), § 60.253(b), § 60.254(b), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after April 28, 2008, and on or before May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(d) The provisions in § 60.251, § 60.252(b)(1) through (3), and (c), § 60.253(b), § 60.254(b) and (c), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles.

### § 60.251 Definitions.

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

(a) *Anthracite* means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, *see* § 60.17).

(b) *Bag leak detection system* means a system that is capable of continuously monitoring relative particulate matter (dust loadings) in the exhaust of a fabric filter to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

(c) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM D388 (incorporated by reference— *see* § 60.17).

(d) *Coal* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* § 60.17).

(2) For units constructed, reconstructed, or modified after May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* § 60.17), and coal refuse.

(e) *Coal preparation and processing 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.

(f) *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. Equipment located at the mine face is not considered to be part of the coal preparation and processing plant.

(g) *Coal refuse* means waste products of coal mining, physical coal cleaning, and coal preparation operations ( *e.g.* culm, gob, *etc.* ) containing coal, matrix material, clay, and other organic and inorganic material.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Design controlled potential PM emissions rate* means the theoretical particulate matter (PM) emissions (Mg) that would result from the operation of a control device at its design emissions rate (grams per dry standard cubic meter (g/dscm)), multiplied by the maximum design flow rate (dry standard cubic meter per minute (dscm/min)), multiplied by 60 (minutes per hour (min/hr)), multiplied by 8,760 (hours per year (hr/yr)), divided by 1,000,000 (megagrams per gram (Mg/g)).

(j) *Indirect thermal dryer* means a thermal dryer that reduces the moisture content of coal through indirect heating of the coal through contact with a heat transfer medium. If the source of heat (the source of combustion or furnace) is subject to another subpart of this part, then the furnace and the associated emissions are not part of the affected facility. However, if the source of heat is not subject to another subpart of this part, then the furnace and the associated emissions are part of the affected facility.

(k) *Lignite* means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, *see* § 60.17).

(l) *Mechanical vent* means any vent that uses a powered mechanical drive (machine) to induce air flow.

(m) *Open storage pile* means any facility, including storage area, that is not enclosed that is used to store coal, including the equipment used in the loading, unloading, and conveying operations of the facility.

(n) *Operating day* means a 24-hour period between 12 midnight and the following midnight during which coal is prepared or processed at any time by the affected facility. It is not necessary that coal be prepared or processed the entire 24-hour period.

(o) *Pneumatic coal-cleaning equipment* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility which classifies coal by size or separates coal from refuse by application of air stream(s).

(p) *Potential combustion concentration* means the theoretical emissions (nanograms per joule (ng/J) or pounds per million British thermal units (lb/MMBtu) heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems, as determined using Method 19 of appendix A-7 of this part.

(q) *Subbituminous coal* means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, *see* § 60.17).

(r) *Thermal dryer* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, 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.

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility in which the moisture content of coal is reduced by either contact with a heated gas stream which is exhausted to the atmosphere or through indirect heating of the coal through contact with a heated heat transfer medium.

(s) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

**§ 60.252 Standards for thermal dryers.**

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified on or before April 28, 2008, subject to the provisions of this subpart must meet the requirements in paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which contain PM in excess of 0.070 g/dscm (0.031 grains per dry standard cubic feet (gr/dscf)); and

(2) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which exhibit 20 percent opacity or greater.

(b) Except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after April 28, 2008, subject to the provisions of this subpart must meet the applicable standards for PM and opacity, as specified in paragraph (b)(1) of this section. In addition, and except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after May 29, 2009, subject to the provisions of this subpart must also meet the applicable standards for sulfur dioxide ($SO_2$ ), and combined nitrogen oxides ($NO_X$ ) and carbon monoxide (CO) as specified in paragraphs (b)(2) and (b)(3) of this section.

(1) The owner or operator must meet the requirements for PM emissions in paragraphs (b)(1)(i) through (iii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed or reconstructed after April 28, 2008, the owner or operator must meet the requirements of (b)(1)(i)(A) and (b)(1)(i)(B).

(A) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that contain PM in excess of 0.023 g/dscm (0.010 grains per dry standard cubic feet (gr/dscf)); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that exhibit 10 percent opacity or greater.

(ii) For each thermal dryer modified after April 28, 2008, the owner or operator must meet the requirements of paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B) of this section.

(A) The owner or operator must not cause to be discharged to the atmosphere from the affected facility any gases which contain PM in excess of 0.070 g/dscm (0.031 gr/dscf); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 20 percent opacity or greater.

(2) Except as provided in paragraph (b)(2)(iii) of this section, for each thermal dryer constructed, reconstructed, or modified after May 27, 2009, the owner or operator must meet the requirements for $SO_2$ emissions in either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$ in excess of 85 ng/J (0.20 lb/MMBtu) heat input; or

(ii) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that either contain $SO_2$ in excess of 520 ng/J (1.20 lb/MMBtu) heat input or contain $SO_2$ in excess of 10 percent of the potential combustion concentration ( *i.e.,* the facility must achieve at least a 90 percent reduction of the potential combustion concentration and may not exceed a maximum emissions rate of 1.2 lb/MMBtu (520 ng/J)).

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to an $SO_2$ limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input are not subject to the $SO_2$ limits of this section.

(3) Except as provided in paragraph (b)(3)(iii) of this section, the owner or operator must meet the requirements for combined $NO_X$ and CO emissions in paragraph (b)(3)(i) or (b)(3)(ii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain a combined concentration of $NO_X$ and CO in excess of 280 ng/J (0.65 lb/MMBtu) heat input.

(ii) For each thermal dryer reconstructed or modified after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain combined concentration of $NO_X$ and CO in excess of 430 ng/J (1.0 lb/MMBtu) heat input.

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to a $NO_X$ limit and/or CO limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input, are not subject to the combined $NO_X$ and CO limits of this section.

(c) Thermal dryers receiving all of their thermal input from an affected facility covered under another 40 CFR Part 60 subpart must meet the applicable requirements in that subpart but are not subject to the requirements in this subpart.

**§ 60.253 Standards for pneumatic coal-cleaning equipment.**

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified on or before April 28, 2008, must meet the requirements of paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess of 0.040 g/dscm (0.017 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit 10 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) The owner of operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess or 0.023 g/dscm (0.010 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit greater than 5 percent opacity.

**§ 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.**

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator 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 constructed, reconstructed, or modified on or before April 28, 2008, gases which exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) through (3) of this section, as applicable to the affected facility.

(1) Except as provided in paragraph (b)(3) of this section, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 10 percent opacity or greater.

(2) The owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf).

(3) Equipment used in the loading, unloading, and conveying operations of open storage piles are not subject to the opacity limitations of paragraph (b)(1) of this section.

(c) The owner or operator of an open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, constructed, reconstructed, or modified after May 27, 2009, must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions as specified in paragraphs (c)(1) through (6) of this section.

(1) The fugitive coal dust emissions control plan must identify and describe the control measures the owner or operator will use to minimize fugitive coal dust emissions from each open storage pile.

(2) For open coal storage piles, the fugitive coal dust emissions control plan must require that one or more of the following control measures be used to minimize to the greatest extent practicable fugitive coal dust: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents on the source (when the provisions of paragraph (c)(6) of this section are met), use of a wind barrier, compaction, or use of a vegetative cover. The owner or operator must select, for inclusion in the fugitive coal dust emissions control plan, the control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.

(3) Any owner or operator of an affected facility that is required to have a fugitive coal dust emissions control plan may petition the Administrator to approve, for inclusion in the plan for the affected facility, alternative control measures other than those specified in paragraph (c)(2) of this section as specified in paragraphs (c)(3)(i) through (iv) of this section.

(i) The petition must include a description of the alternative control measures, a copy of the fugitive coal dust emissions control plan for the affected facility that includes the alternative control measures, and information sufficient for EPA to evaluate the demonstrations required by paragraph (c)(3)(ii) of this section.

(ii) The owner or operator must either demonstrate that the fugitive coal dust emissions control plan that includes the alternate control measures will provide equivalent overall environmental protection or demonstrate that it is either economically or technically infeasible for the affected facility to use the control measures specifically identified in paragraph (c)(2).

(iii) While the petition is pending, the owner or operator must comply with the fugitive coal dust emissions control plan including the alternative control measures submitted with the petition. Operation in accordance with the plan submitted with the petition shall be deemed to constitute compliance with the requirement to operate in accordance

with a fugitive coal dust emissions control plan that contains one of the control measures specifically identified in paragraph (c)(2) of this section while the petition is pending.

(iv) If the petition is approved by the Administrator, the alternative control measures will be approved for inclusion in the fugitive coal dust emissions control plan for the affected facility. In lieu of amending this subpart, a letter will be sent to the facility describing the specific control measures approved. The facility shall make any such letters and the applicable fugitive coal dust emissions control plan 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.

(4) The owner or operator must submit the fugitive coal dust emissions control plan to the Administrator or delegated authority as specified in paragraphs (c)(4)(i) and (c)(4)(ii) of this section.

(i) The plan must be submitted to the Administrator or delegated authority prior to startup of the new, reconstructed, or modified affected facility, or 30 days after the effective date of this rule, whichever is later.

(ii) The plan must be revised as needed to reflect any changing conditions at the source. Such revisions must be dated and submitted to the Administrator or delegated authority before a source can operate pursuant to these revisions. The Administrator or delegated authority may also object to such revisions as specified in paragraph (c)(5) of this section.

(5) The Administrator or delegated authority may object to the fugitive coal dust emissions control plan as specified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) The Administrator or delegated authority may object to any fugitive coal dust emissions control plan that it has determined does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(ii) If an objection is raised, the owner or operator, within 30 days from receipt of the objection, must submit a revised fugitive coal dust emissions control plan to the Administrator or delegated authority. The owner or operator must operate in accordance with the revised fugitive coal dust emissions control plan. The Administrator or delegated authority retain the right, under paragraph (c)(5) of this section, to object to the revised control plan if it determines the plan does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(6) Where appropriate chemical dust suppression agents are selected by the owner or operator as a control measure to minimize fugitive coal dust emissions, (1) only chemical dust suppressants with Occupational Safety and Health Administration (OSHA)-compliant material safety data sheets (MSDS) are to be allowed; (2) the MSDS must be included in the fugitive coal dust emissions control plan; and (3) the owner or operator must consider and document in the fugitive coal dust emissions control plan the site-specific impacts associated with the use of such chemical dust suppressants.

**§ 60.255 Performance tests and other compliance requirements.**

(a) An owner or operator of each affected facility that commenced construction, reconstruction, or modification on or before April 28, 2008, must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emission standards using the methods identified in § 60.257.

(b) An owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of § 60.8 and the methods identified in § 60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section.

(1) For each affected facility subject to a PM, $SO_2$ , or combined $NO_X$ and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 30 calendar days after the next operating day.

(2) For each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section.

(i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed.

(ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in § 60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests.

(c) If any affected coal processing and conveying equipment ( *e.g.,* breakers, crushers, screens, conveying systems), coal storage systems, or coal transfer and loading systems that commenced construction, reconstruction, or modification after April 28, 2008, are enclosed in a building, and emissions from the building do not exceed any of the standards in *§* 60.254 that apply to the affected facility, then the facility shall be deemed to be in compliance with such standards.

(d) An owner or operator of an affected facility (other than a thermal dryer) that commenced construction, reconstruction, or modification after April 28, 2008, is subject to a PM emission standard and uses a control device with a design controlled potential PM emissions rate of 1.0 Mg (1.1 tons) per year or less is exempted from the requirements of paragraphs (b)(1)(i) and (ii) of this section provided that the owner or operator meets all of the conditions specified in paragraphs (d)(1) through (3) of this section. This exemption does not apply to thermal dryers.

(1) PM emissions, as determined by the most recent performance test, are less than or equal to the applicable limit,

(2) The control device manufacturer's recommended maintenance procedures are followed, and

(3) All 6-minute average opacity readings from the most recent performance test are equal to or less than half the applicable opacity limit or the monitoring requirements in paragraphs (e) or (f) of this section are followed.

(e) For an owner or operator of a group of up to five of the same type of affected facilities that commenced construction, reconstruction, or modification after April 28, 2008, that are subject to PM emissions standards and use identical control devices, the Administrator or delegated authority may allow the owner or operator to use a single PM performance test for one of the affected control devices to demonstrate that the group of affected facilities is in compliance with the applicable emissions standards provided that the owner or operator meets all of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) PM emissions from the most recent performance test for each individual affected facility are 90 percent or less of the applicable PM standard;

(2) The manufacturer's recommended maintenance procedures are followed for each control device; and

(3) A performance test is conducted on each affected facility at least once every 5 calendar years.

(f) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, may elect to comply with the requirements in paragraph (f)(1) or (f)(2) of this section.

(1) Monitor visible emissions from each affected facility according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.

(i) Conduct one daily 15-second observation each operating day for each affected facility (during normal operation) when the coal preparation and processing plant is in operation. Each observation must be recorded as either visible emissions observed or no visible emissions observed. Each observer determining the presence of visible emissions must meet the training requirements specified in § 2.3 of Method 22 of appendix A-7 of this part. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A-4 of this part, performance test must be conducted within 45 operating days.

(ii) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(iii) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

(2) Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15 seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. 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 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. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator.

(g) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, subject to a visible emissions standard under this subpart may install, operate, and maintain a continuous opacity monitoring system (COMS). Each COMS used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (g)(1) and (2) of this section.

(1) The COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(2) The COMS must comply with the quality assurance requirements in paragraphs (g)(2)(i) through (v) of this section.

(i) The owner or operator must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) The owner or operator must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(iii) The owner or operator must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known

obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(iv) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(v) The owner or operator must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(h) The owner or operator of each affected coal truck dump operation that commenced construction, reconstruction, or modification after April 28, 2008, must meet the requirements specified in paragraphs (h)(1) through (3) of this section.

(1) Conduct an initial performance test using Method 9 of appendix A-4 of this part according to the requirements in paragraphs (h)(1)(i) and(ii).

(i) Opacity readings shall be taken during the duration of three separate truck dump events. Each truck dump event commences when the truck bed begins to elevate and concludes when the truck bed returns to a horizontal position.

(ii) Compliance with the applicable opacity limit is determined by averaging all 15-second opacity readings made during the duration of three separate truck dump events.

(2) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(3) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

**§ 60.256 Continuous monitoring requirements.**

(a) The owner or operator of each affected facility constructed, reconstructed, or modified on or before April 28, 2008, must meet the monitoring requirements specified in paragraphs (a)(1) and (2) of this section, as applicable to the affected facility.

(1) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(i) 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).

(ii) For affected facilities that use wet scrubber emission control equipment:

(A) 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.

(B) 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 shall have discretion to grant requests for approval of alternative monitoring locations.

(2) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b).

(b) The owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1) through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent.

(1) For mechanical vents with fabric filters (baghouses) with design controlled potential PM emissions rates of 25 Mg (28 tons) per year or more, a bag leak detection system according to the requirements in paragraph (c) of this section.

(2) For mechanical vents with wet scrubbers, monitoring devices according to the requirements in paragraphs (b)(2)(i) through (iv) of this section.

(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 flow rate to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply flow rate.

(iii) A monitoring device for the continuous measurement of the pH of the wet scrubber liquid. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design pH.

(iv) An average value for each monitoring parameter must be determined during each performance test. Each monitoring parameter must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(3) For mechanical vents with control equipment other than wet scrubbers, a monitoring device for the continuous measurement of the reagent injection flow rate to the control equipment, as applicable. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design injection flow rate. An average reagent injection flow rate value must be determined during each performance test. The reagent injection flow rate must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(c) Each bag leak detection system used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (c)(1) through (3) of this section.

(1) The bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (mg/dscm) (0.00044 grains per actual cubic foot (gr/acf)) or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means ( *e.g.,* using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(2)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. This plan must be submitted to the Administrator or delegated authority 30 days prior to startup of the affected facility. The owner or operator must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow the owner and operator more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(3) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective fabric filter compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the PM emissions.

**§ 60.257 Test methods and procedures.**

(a) The owner or operator must determine compliance with the applicable opacity standards as specified in paragraphs (a)(1) through (3) of this section.

(1) Method 9 of appendix A-4 of this part and the procedures in § 60.11 must be used to determine opacity, with the exceptions specified in paragraphs (a)(1)(i) and (ii).

(i) The duration of the Method 9 of appendix A-4 of this part performance test shall be 1 hour (ten 6-minute averages).

(ii) If, during the initial 30 minutes of the observation of a Method 9 of appendix A-4 of this part performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes.

(2) To determine opacity for fugitive coal dust emissions sources, the additional requirements specified in paragraphs (a)(2)(i) through (iii) must be used.

(i) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back.

(ii) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction.

(iii) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission.

(3) A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions specified in paragraphs (a)(3)(i) through (iii) of this section are met.

(i) No more than three emissions points may be read concurrently.

(ii) All three emissions points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.

(iii) If an opacity reading for any one of the three emissions points is within 5 percent opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings for the other two points and continue reading just that single point.

(b) The owner or operator must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emissions standards specified in § 60.252 according to the requirements in § 60.8 using the applicable test methods and procedures in paragraphs (b)(1) through (8) of this section.

(1) Method 1 or 1A of appendix A-4 of this part shall be used to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(2) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A-4 of this part shall be used to determine the volumetric flow rate of the stack gas.

(3) Method 3, 3A, or 3B of appendix A-4 of this part shall be used to determine the dry molecular weight of the stack gas. The owner or operator may use ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses (incorporated by reference— *see* § 60.17) as an alternative to Method 3B of appendix A-2 of this part.

(4) Method 4 of appendix A-4 of this part shall be used to determine the moisture content of the stack gas.

(5) Method 5, 5B or 5D of appendix A-4 of this part or Method 17 of appendix A-7 of this part shall be used to determine the PM concentration as follows:

(i) 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. A minimum of three valid test runs are needed to comprise a PM performance test.

(ii) Method 5 of appendix A of this part shall be used only to test emissions from affected facilities without wet flue gas desulfurization (FGD) systems.

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

(iv) Method 5D of appendix A-4 of this part shall be used for positive pressure fabric filters and other similar applications ( *e.g.,* stub stacks and roof vents).

(v) 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.

(6) Method 6, 6A, or 6C of appendix A-4 of this part shall be used to determine the $SO_2$ concentration. A minimum of three valid test runs are needed to comprise an $SO_2$ performance test.

(7) Method 7 or 7E of appendix A-4 of this part shall be used to determine the $NO_X$ concentration. A minimum of three valid test runs are needed to comprise an $NO_X$ performance test.

(8) Method 10 of appendix A-4 of this part shall be used to determine the CO concentration. A minimum of three valid test runs are needed to comprise a CO performance test. CO performance tests are conducted concurrently (or within a 60-minute period) with $NO_X$ performance tests.

**§ 60.258 Reporting and recordkeeping.**

(a) The owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook shall record the following:

(1) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, shall be noted.

(2) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted.

(3) The amount and type of coal processed each calendar month.

(4) The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant.

(5) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, shall be noted.

(6) Monthly certification that the fugitive coal dust emissions control plan was implemented as described. Any variance from the plan, if any, shall be noted. A copy of the applicable fugitive coal dust emissions control plan and any letters from the Administrator providing approval of any alternative control measures shall be maintained with the

logbook. Any actions, *e.g.* objections, to the plan and any actions relative to the alternative control measures, *e.g.* approvals, shall be noted in the logbook as well.

(7) For each bag leak detection system, the owner or operator must keep the records specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the cause of the alarm was alleviated within 3 hours of the alarm.

(8) A copy of any applicable monitoring plan for a digital opacity compliance system and monthly certification that the plan was implemented as described. Any variance from plan, if any, shall be noted.

(9) During a performance test of a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the scrubber pressure loss, water supply flow rate, and pH of the wet scrubber liquid.

(10) During a performance test of control equipment other than a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the reagent injection flow rate, as applicable.

(b) For the purpose of reports required under section 60.7(c), any owner operator subject to the provisions of this subpart also shall report semiannually periods of excess emissions as follow:

(1) The owner or operator of an affected facility with a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the scrubber pressure loss, water supply flow rate, or pH of the wet scrubber liquid vary by more than 10 percent from the average determined during the most recent performance test.

(2) The owner or operator of an affected facility with control equipment other than a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the reagent injection flow rate, as applicable, vary by more than 10 percent from the average determined during the most recent performance test.

(3) All 6-minute average opacities that exceed the applicable standard.

(c) The owner or operator of an affected facility shall submit the results of initial performance tests to the Administrator or delegated authority, consistent with the provisions of section 60.8. The owner or operator who elects to comply with the reduced performance testing provisions of sections 60.255(c) or (d) shall include in the performance test report identification of each affected facility that will be subject to the reduced testing. The owner or operator electing to comply with section 60.255(d) shall also include information which demonstrates that the control devices are identical.

(d) After July 1, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.* For performance tests that cannot be entered into WebFIRE ( *i.e.,* Method 9 of appendix A-4 of this part opacity performance tests) the owner or operator of the affected facility must mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711.

# Attachment D

**Electronic Code of Federal Regulations**

**Title 40: Protection of Environment**

**40 CFR 60, Subpart KKKK—Standards of Performance for Stationary Combustion Turbines**

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

**Introduction**

**§ 60.4300 What is the purpose of this subpart?**

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

**Applicability**

**§ 60.4305 Does this subpart apply to my stationary combustion turbine?**

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

**§ 60.4310 What types of operations are exempt from these standards of performance?**

(a) Emergency combustion turbines, as defined in § 60.4420(i), are exempt from the nitrogen oxides ($NO_X$ ) emission limits in § 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the $NO_X$ emission limits in § 60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

**Emission Limits**

**§ 60.4315 What pollutants are regulated by this subpart?**

The pollutants regulated by this subpart are nitrogen oxide ($NO_X$ ) and sulfur dioxide ($SO_2$ ).

**§ 60.4320 What emission limits must I meet for nitrogen oxides (NOX )?**

(a) You must meet the emission limits for $NO_X$ specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for $NO_X$ .

**§ 60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?**

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

**§ 60.4330 What emission limits must I meet for sulfur dioxide (SO2 )?**

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain $SO_2$ in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng $SO_2$ /J (0.060 lb $SO_2$ /MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain $SO_2$ in excess of 65 ng $SO_2$ /J (0.15 lb $SO_2$ /MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain $SO_2$ in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng $SO_2$ /J (0.42 lb $SO_2$ /MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

**General Compliance Requirements**

**§ 60.4333 What are my general requirements for complying with this subpart?**

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable $NO_X$ emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

**Monitoring**

**§ 60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?**

(a) If you are using water or steam injection to control $NO_X$ emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a $NO_X$ monitor and a diluent gas (oxygen ($O_2$ ) or carbon dioxide ($CO_2$ )) monitor, to determine the hourly $NO_X$ emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

**§ 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?**

(a) If you are not using water or steam injection to control $NO_X$ emissions, you must perform annual performance tests in accordance with § 60.4400 to demonstrate continuous compliance. If the $NO_X$ emission result from the performance test is less than or equal to 75 percent of the $NO_X$ emission 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 $NO_X$ emission 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 $NO_X$ formation 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-$NO_X$ mode.

(iii) For any turbine that uses SCR to reduce $NO_X$ emissions, 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 $NO_X$ emission 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 $NO_X$ CEMS is chosen:

(a) Each $NO_X$ diluent 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 $NO_X$ diluent 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 $NO_X$ monitor 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 $NO_X$ emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

**§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?**

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in § 60.4345(b), is obtained for both $NO_X$ and diluent monitors, the data acquisition and handling system must calculate and record the hourly $NO_X$ emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$ (or the hourly average $CO_2$ concentration is less than 1.0 percent $CO_2$ ), a diluent cap value of 19.0 percent $O_2$ or 1.0 percent $CO_2$ (as applicable) may be used in the emission calculations.

(c) Correction of measured $NO_X$ concentrations to 15 percent $O_2$ is not allowed.

(d) If you have installed and certified a $NO_X$ diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average $NO_X$ emission rates, in units of the emission standards under § 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly $NO_X$ emission rate, in lb/MWh,

$(NO_X)_h$ = hourly $NO_X$ emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.* , calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

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 $3.413 \times 10_6$ = 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 = $NO_X$ emission rate in lb/MWh,

$(NO_X)_m$ = $NO_X$ emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in § 60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in § 60.4380(b)(1).

**§ 60.4355 How do I establish and document a proper parameter monitoring plan?**

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§ 60.4335 and 60.4340 must be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the $NO_X$ emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the $NO_X$ emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the

justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in § 75.19 or the $NO_X$ emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

**§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?**

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used.

**§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?**

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng $SO_2$ /J (0.060 lb $SO_2$ /MMBtu) heat input for units located in continental areas and 180 ng $SO_2$ /J (0.42 lb $SO_2$ /MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng $SO_2$ /J (0.060 lb $SO_2$ /MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng $SO_2$ /J (0.42 lb $SO_2$ /MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng $SO_2$ /J (0.060 lb $SO_2$ /MMBtu) heat input for continental areas or 180 ng $SO_2$ /J (0.42 lb $SO_2$ /MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

**§ 60.4370 How often must I determine the sulfur content of the fuel?**

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter ( *i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

**Reporting**

**§ 60.4375 What reports must I submit?**

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with § 60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

**§ 60.4380 How are excess emissions and monitor downtime defined for NOX ?**

For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for $NO_X$ control 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 $NO_X$ emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a “4-hour rolling average $NO_X$ emission rate” is the arithmetic average of the average $NO_X$ emission 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 $NO_X$ emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid $NO_X$ emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a “30-day rolling average $NO_X$ emission rate” is the arithmetic average of all hourly $NO_X$ emission 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 $NO_X$ emissions rates for the preceding 30 unit operating days if a valid $NO_X$ emission 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: $NO_X$ concentration, CO2 or $O_2$ concentration, 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 $NO_X$ emission 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 SO2 ?**

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:

$$E = \frac{1.194 \times 10^{-7} * (NO_x)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = $NO_X$ emission rate, in lb/MWh

$1.194 \times 10^{-7}$ = 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 $NO_X$ concentrations 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 $NO_X$ concentration during the stratification test; or

(B) For turbines with a $NO_X$ standard 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 $NO_X$ concentrations 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 $NO_X$ standard 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 $NO_X$ concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent $CO_2$ (or $O_2$ ) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total $NO_X$ emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control $NO_X$ with no additional post-combustion $NO_X$ control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320 $NO_X$ emission limit.

(4) Compliance with the applicable emission limit in § 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average $NO_X$ emission rate at each tested level meets the applicable emission limit in § 60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

**§ 60.4405 How do I perform the initial performance test if I have chosen to install a NOX -diluent CEMS?**

If you elect to install and certify a $NO_X$ -diluent CEMS under § 60.4345, then the initial performance test required under § 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable $NO_X$ emission limit under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4335.

(d) Compliance with the applicable emission limit in § 60.4320 is achieved if the arithmetic average of all of the $NO_X$ emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

**§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?**

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of $NO_X$ emission controls in accordance with § 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.4355.

**§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?**

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent $SO_2$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see § 60.17) for natural gas or ASTM D4177 (incorporated by reference, see § 60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17).

(2) Measure the $SO_2$ concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see § 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the $SO_2$ emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = $SO_2$ emission rate, in lb/MWh

$1.664 \times 10^{-7}$ = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average $SO_2$ concentration for the run, in ppm

$Q_{std}$ = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(3) Measure the $SO_2$ and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see § 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part

to calculate the $SO_2$ emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the $SO_2$ emission rate in lb/MWh.

(b) [Reserved]

**Definitions**

**§ 60.4420 What definitions apply to this subpart?**

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

*Biogas* means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and $CO_2$ .

*Combined cycle combustion turbine* means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

*Combined heat and power combustion turbine* means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

*Combustion turbine model* means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

*Combustion turbine test cell/stand* means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

*Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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

*Efficiency* means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

*Emergency combustion turbine* means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

*Excess emissions* means a specified averaging period over which either (1) the $NO_X$ emissions are higher than the applicable emission limit in § 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

*Gross useful output* means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross

electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

*Heat recovery steam generating unit* means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

*Integrated gasification combined cycle electric utility steam generating unit* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

*ISO conditions* means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

*Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

*Natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

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

*Peak load* means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

*Regenerative cycle combustion turbine* means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

*Simple cycle combustion turbine* means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

*Stationary combustion turbine* means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

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

*Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

*Useful thermal output* means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications

other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

**Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines**

| Combustion turbine type | Combustion turbine heat input at peak load (HHV) | $NO_X$ emission standard |
|---|---|---|
| New turbine firing natural gas, electric generating | 50 MMBtu/h | 42 ppm at 15 percent $O_2$ or 290 ng/J of useful output (2.3 lb/MWh). |
| New turbine firing natural gas, mechanical drive | 50 MMBtu/h | 100 ppm at 15 percent $O_2$ or 690 ng/J of useful output (5.5 lb/MWh). |
| New turbine firing natural gas | 50 MMBtu/h and 850 MMBtu/h | 25 ppm at 15 percent $O_2$ or 150 ng/J of useful output (1.2 lb/MWh). |
| New, modified, or reconstructed turbine firing natural gas | 850 MMBtu/h | 15 ppm at 15 percent $O_2$ or 54 ng/J of useful output (0.43 lb/MWh) |
| New turbine firing fuels other than natural gas, electric generating | 50 MMBtu/h | 96 ppm at 15 percent $O_2$ or 700 ng/J of useful output (5.5 lb/MWh). |
| New turbine firing fuels other than natural gas, mechanical drive | 50 MMBtu/h | 150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh). |
| New turbine firing fuels other than natural gas | 50 MMBtu/h and 850 MMBtu/h | 74 ppm at 15 percent $O_2$ or 460 ng/J of useful output (3.6 lb/MWh). |
| New, modified, or reconstructed turbine firing fuels other than natural gas | 850 MMBtu/h | 42 ppm at 15 percent $O_2$ or 160 ng/J of useful output (1.3 lb/MWh). |
| Modified or reconstructed turbine | 50 MMBtu/h | 150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh). |
| Modified or reconstructed turbine firing natural gas | 50 MMBtu/h and 850 MMBtu/h | 42 ppm at 15 percent $O_2$ or 250 ng/J of useful output (2.0 lb/MWh). |
| Modified or reconstructed turbine firing fuels other than natural gas | 50 MMBtu/h and 850 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). |

| Combustion turbine type | Combustion turbine heat input at peak load (HHV) | $NO_x$ emission standard |
|---|---|---|
| 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

**Electronic Code of Federal Regulations**

**Title 40: Protection of Environment**

**40 CFR 63, 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 the FEDERAL 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 turbine as defined in this subpart,<br>2. a lean premix oil-fired stationary combustion turbine as defined in this subpart,<br>3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or<br>4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart. | limit the concentration of formaldehyde to 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 $O_2$concentration at the sampling port location AND | Method 3A or 3B of 40 CFR part 60, appendix A | measurements to determine $O_2$concentration must be made at the same time as the 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 | |

| Citation | Subject | Applies to Subpart YYYY | Explanation |
|---|---|---|---|
| § 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 | |

| Citation | Subject | Applies to Subpart YYYY | Explanation |
|---|---|---|---|
| § 63.8(c)(1)(iii) | SSMP for CMS required | Yes | |
| § 63.8(c)(2)-(3) | Monitoring system installation | Yes | |
| § 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 alternative to relative accuracy test audit (RATA) is exceeded | Yes | If alternative is in use. |
| § 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 | |

| Citation | Subject | Applies to Subpart YYYY | Explanation |
|---|---|---|---|
| § 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 | |

# Indiana Department of Environmental Management
# Office of Air Quality

## Technical Support Document (TSD) for a Part 70 Significant Source and Significant Permit Modification

### Source Description and Location

| | |
|---|---|
| Source Name: | Purdue University |
| Source Location: | 401 S. Grant St., Freehafer Hall of Administrative Services |
| County: | Tippecanoe |
| SIC Code: | 8221 |
| Operation Permit No.: | T157-27313-00012 |
| Operation Permit Issuance Date: | August 27, 2010 |
| Significant Source Modification No.: | 157-34219-00012 |
| Significant Permit Modification No.: | 157-34221-00012 |
| Permit Reviewer: | Deena Patton |

### Existing Approvals

The source was issued Part 70 Operating Permit No. T157-27313-00012 on August 27, 2010. The source has since received the following approvals:

| Permit Type | Permit Number | Issuance Date |
|---|---|---|
| Significant Source Modification | 157-27361-00012 | July 9, 2010 |
| Administrative Amendment | 157-30222-00012 | March 2, 2011 |
| Revocation | 157-30359-00012 | March 21, 2011 |
| Administrative Amendment | 157-30374-00012 | April 19, 2011 |
| Significant Permit Modification | 157-30742-00012 | May 1, 2012 |
| Significant Source Modification | 157-32230-00012 | March 8, 2013 |
| Significant Permit Modification | 157-32275-00012 | March 27, 2013 |

### 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 July 20, 2012, for the 2008 8-hour ozone standard.[1] |
| $PM_{2.5}$ | Unclassifiable or attainment effective April 5, 2005, for the annual $PM_{2.5}$ standard. |
| $PM_{2.5}$ | Unclassifiable or attainment effective December 13, 2009, for the 24-hour $PM_{2.5}$ standard. |
| $PM_{10}$ | Unclassifiable effective November 15, 1990. |
| $NO_2$ | Cannot be classified or better than national standards. |
| Pb | Unclassifiable or attainment effective December 31, 2011. |

[1]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 ($NO_x$) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and $NO_x$ emissions are considered when evaluating the rule applicability relating to ozone. Tippecanoe County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and $NO_x$ emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
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 $PM_{2.5}$, $SO_2$, and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
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 classified as a fossil fuel boilers (or combinations thereof) totaling more than two hundred fifty million (250,000,000) British thermal units per hour heat input , it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

## Source Status

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

| **Pollutant** | **Emissions** (ton/yr) |
|---|---|
| PM | >100 |
| $PM_{10}$ | >100 |
| $PM_{2.5}$ | >100 |
| $SO_2$ | >100 |
| VOC | >100 |
| CO | >100 |
| $NO_X$ | >100 |
| GHGs as $CO_2e$ | >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 Technical Support Document for Significant Permit Modification No.: 157-32275-00012, issued on March 27, 2013

(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 on February 21, 2014, relating to the construction of a portable bulk storage bin to store limestone onsite. The following is a list of the new emission units and pollution control devices:

(a) One (1) temporary portable bulk limestone storage bin, permitted in 2014, identified as LS2-T, with a maximum capacity of 25,492 tons of limestone per year, using cartridge filter (BVLI5) as control, and exhausting to stack BVLI5.

## Enforcement Issues

IDEM is aware that equipment has been constructed and operated prior to receipt of the proper permit. IDEM is reviewing this matter and will take the appropriate action. This proposed approval is intended to satisfy the requirements of the construction permit rules.

Purdue believes that the existing limestone bin was on the verge of failure which resulted in the need to install the temporary unit.

## 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 | 28.04 |
| $PM_{10}$ | 28.04 |
| $PM_{2.5}$ | 28.04 |
| $SO_2$ | 0.00 |
| VOC | 0.00 |
| CO | 0.00 |
| $NO_X$ | 0.00 |
| Single HAPs | 0.00 |
| Total HAPs | 0.00 |

Appendix A of this TSD reflects the unrestricted potential emissions of the modification.

This source modification is subject to 326 IAC 2-7-10.5(g)(4), since the emission unit has a potential to emit greater than twenty-five (25) tons per year of PM, PM10, and PM2.5 and the emission unit that it is replacing will not be removed from the source. 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 this modification does involves new emission limits.

## 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 source modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

| | **Potential to Emit** (ton/yr) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Process / Emission Unit** | **PM** | **$PM_{10}$** | **$PM_{2.5}$*** | **$SO_2$** | **VOC** | **CO** | **$NO_X$** | **GHGs** |
| **LS2-T** | <25 | <15 | <10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Total for Modification | <25 | <15 | <10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PSD Major Source Thresholds | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100,000 $CO_2e$ |
| Significant Level | 25 | 15 | 10 | 40 | 40 | 100 | 40 | 75,000 $CO_2e$ |

*$PM_{2.5}$ listed is direct $PM_{2.5}$.

This modification to an existing major stationary source is not major because the emissions increase is less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Since this source is considered a major PSD source and the unrestricted potential to emit of this modification is greater than twenty-five (25) tons of PM per year, fifteen (15) tons of $PM_{10}$ per year, and ten (10) tons of $PM_{2.5}$ per year, this source has elected to limit the potential to emit of this modification as follows:

(a) The PM emission rate from LS2-T, controlled by baghouse, shall be less than 5.7 pounds per hour.

(b) The $PM_{10}$ emission rate from LS2-T shall be less than 3.42 pounds per hour.

(c) The $PM_{2.5}$ emission rate from LS2-T, shall be less than 2.28 pounds per hour

Compliance with these emission limits will ensure that the potential to emit from this modification is less than twenty-five (25) tons of PM per year, less than fifteen (15) tons of $PM_{10}$ per year, and less than ten (10) tons of $PM_{2.5}$ per year and therefore will render the requirements of 326 IAC 2-2 not applicable.

## Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this modification:

**NSPS:**

(a) There are no New Source Performance Standards (NSPS)(326 IAC 12 and 40 CFR Part 60) included in the permit.

**NESHAP:**

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included in the permit.

**CAM:**

(c) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the Part 70 major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new or modified emission unit involved:

| **CAM Applicability Analysis** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Emission Unit** | **Control Device Used** | **Emission Limitation** (Y/N) | **Uncontrolled PTE** (ton/yr) | **Controlled PTE** (ton/yr) | **Part 70 Major Source Threshold** (ton/yr) | **CAM Applicable** (Y/N) | **Large Unit** (Y/N) |
| LS2-T (PM10) | Baghouse | Y | 28.04 | 0.28 | 100 | N | N |
| LS2-T (PM2.5) | Baghouse | Y | 28.04 | 0.28 | 100 | N | N |

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable the temporary portable bulk storage bin units as part of this modification, because the uncontrolled emissions of PM, PM10, and PM2.5 are less than 100 tons per year.

## State Rule Applicability Determination

The following state rules are applicable to the source due to the modification:

**326 IAC 2-2 (PSD)**
PSD applicability is discussed under the Permit Level Determination – PSD section.

**326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))**
The operation of the portable silo (LS2-T) will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

**326 IAC 2-6 (Emission Reporting)**
Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, this source is subject to 326 IAC 2-6 (Emission Reporting). In accordance with the compliance schedule in 326 IAC 2-6-3(a)(1), an emission statement must be submitted annually. The report is due no later than July 1st and subsequent reports are due every year thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c).

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**
Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the temporary portable bulk storage bin shall not exceed 8.39 pounds per hour when operating at a process weight rate of 2.91 tons per hour. The pound per hour limitation was calculated with the following equation:

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

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

## Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The Compliance Determination and Monitoring Requirements applicable to this modification are as follows:

(a) The temporary portable bulk storage bin has no applicable compliance monitoring conditions.

(b) Since this is a temporary operation no testing requirements are needed.

## 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]**

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:

***

**(p) One (1) temporary portable bulk limestone storage bin, permitted in 2014, identified as LS2-T, with a maximum capacity of 25,492 tons of limestone per year, using cartridge filter (BVLI5) as control, and exhausting to stack BVLI5.**

***

**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.

**(p) One (1) temporary portable bulk limestone storage bin, permitted in 2014, identified as LS2-T, with a maximum capacity of 25,492 tons of limestone per year, using cartridge filter (BVLI5) as control, and exhausting to stack BVLI5.**

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]

**(a)** 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).

**(b) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the temporary portable bulk storage bin shall not exceed 8.39 pounds per hour when operating at a process weight rate of 2.91 tons per hour.**

The pounds per hour limitations were calculated with the following equation:

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).

***

**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.

****

## Conclusion and Recommendation

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 157-34219-00012 and Significant Permit Modification No. 157-34221-00012. 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 Deena Patton 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) 234-5400 or toll free at 1-800-451-6027 extension 4-5400.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.idem.in.gov

**Appendix A: Emissions Calculations**
**Summary**
**Company Name: Purdue University**
**Address City IN Zip: 401 S. Grant Street, Freehafer Hall of Adminstrative Services**
**Operating Permit Number: 157-27313-00012**
**Significant Source Modification No.: 157-34219-00012**
**Significant Permit Modification No.: 157-34221-00012**
**Permit Reviewer: Deena Patton**

*LS1 will be undergoing repairs, thus an alternative system is required to maintain the limestone injection on Boiler 5.

| Uncontrolled Potential to Emit (ton/yr) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Emission Unit | PM | PM10 | PM2.5 | SO2 | Nox | VOC | CO | GHGs | HAPs | Worst Single HAP | |
| LS2-T | 28.04 | 28.04 | 28.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | NA |
| **Total** | **28.04** | **28.04** | **28.04** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **NA** |

| Controlled Potential to Emit (ton/yr) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Emission Unit | PM | PM10 | PM2.5 | SO2 | Nox | VOC | CO | GHGs | HAPs | Worst Single HAP | |
| LS2-T | 0.28 | 0.28 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | NA |
| **Total** | **0.28** | **0.28** | **0.28** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **NA** |

| Limited Potential to Emit (ton/yr) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Emission Unit | PM | PM10 | PM2.5 | SO2 | Nox | VOC | CO | GHGs | HAPs | Worst Single HAP | |
| LS2-T | <25 | <15 | <10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | NA |
| **Total** | **<25** | **<15** | **<10** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **NA** |

**Appendix A: Emissions Calculations**
**LS2-T Potential to Emit Particulates**

**Company Name:** Purdue University
**Address City IN Zip:** 401 S. Grant Street, Freehafer Hall of Adminstrative Services
**Operating Permit Number:** 157-27313-00012
**Significant Source Modification No.:** 157-34219-00012
**Significant Permit Modification No.:** 157-34221-00012
**Permit Reviewer:** Deena Patton

| Emission Unit | Throughput (ton/yr) | Emission Factor PM/PM10/PM2.5 (lb/ton)* | Uncontrolled Emissions PM/PM10/PM2.5 (lb/yr) | Uncontrolled Emissions PM/PM10/PM2.5 (lb/hr) | Uncontrolled Emissions PM/PM10/PM2.5 (ton/yr) | Control Efficiency (%) | Controlled Emissions PM/PM10/PM2.5 (ton/yr) |
|---|---|---|---|---|---|---|---|
| Limestone Portable Bulk Storage Bin (LS2-T) | 25,492 | 2.2 | 56082.40 | 6.40 | **28.04** | 99% | **0.28** |

*Emission Factors from AP 42 Chapter 11.17 Table 4 (Limestone Transfer and Conveyance)

Methodology:
Uncontrolled Emissions PM/PM10/PM2.5 (lb/yr) = Throughput (ton/yr) * Emisson Factor PM/PM10/PM2.5 (lb/ton)
Uncontrolled Emissions PM/PM10/PM2.5 (ton/yr) = Uncontrolled Emissions PM/PM10/PM2.5 (lb/yr) / 2000lbs/ton
Controlled Emissons PM/PM10/PM2.5 (ton/yr) = Uncontrolled Emissions PM/PM10/PM2.5 (ton/yr) * (1-Control Efficiency)

326 IAC 6-3-2 Applicability

For process weight rates up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

| | E (ton/yr) | E (lb/hr) | P (tons/hr) | Controlled needed to comply? | Control Efficiency needed (%) |
|---|---|---|---|---|---|
| E=4.10P^0.67 | 36.73 | 8.39 | 2.91 | N | 70.5 |

Where E= Rate of emissions in pounds per hour
P = Process weight rate in tons per hour

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

**Michael R. Pence**
*Governor*

**Thomas W. Easterly**
*Commissioner*

**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: May 15, 2014

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

SUBJECT: Final Decision
Title V - Significant Source Modification
157 - 34219 - 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:
Michael Cline, VP - Physical Facilities
David Jordan Environmental Resources Management (ERM)
Qaiser P.E. Cornerstone Environmental
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 6/13/2013

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**Michael R. Pence**
*Governor*

**Thomas W. Easterly**
*Commissioner*

May 15, 2014

TO: West Lafayette Public Library 208 W Columbia St West Lafayette IN

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 - 34219 - 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 6/13/2013

# Mail Code 61-53

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| IDEM Staff | LPOGOST 5/15/2014<br>Purdue University 157 - 34219 - 00012 final) | | | AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING |
| Name and address of Sender | ▶ | Indiana Department of Environmental Management<br>Office of Air Quality – Permits Branch<br>100 N. Senate<br>Indianapolis, IN 46204 | Type of Mail:<br>**CERTIFICATE OF MAILING ONLY** | |

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| 2 | | Michael Cline VP - Physical Facilities Purdue University 401 S Grant St, 1662 Freehafer West Lafayette IN 47906-5991 *(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 Columbia 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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FACSIMILIE OF PS Form 3877

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| 1 | | Qaiser P.E. Cornerstone Environmental 880 Lennox Ct. Zionsville IN 46077 (Consultant) | | | | | | | | | |
| 2 | | Mr. Allen Hoffman 4740 Masons Ridge Rd. Lafayette IN 47909 *(Affected Party)* | | | | | | | | | |
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