INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

TO: Interested Parties / Applicant

DATE: December 28, 2012

RE: NIPSCO –Schahfer Generating Station / 073-29983-00008

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

Notice of Decision: Approval – Effective Immediately

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

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

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

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

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

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

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

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

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

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

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

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

Enclosures
FNTVOP.dot12/3/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

NIPSCO - Schahfer Generating Station
2723 East 1500 North
Wheatfield, Indiana 46392

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

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

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

Operation Permit No.: T073-29983-00008	
Issued by: Tripurari Sinha Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: December 28, 2012 Expiration Date: December 28, 2017

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F. PROVISION OF NIPSCO CONSENT DECREE APPLICABLE TO SCHAHFER GENERATING STATION

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G Clean Air Interstate (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

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

Attachment A - Decree Paragraphs and Tables
Attachment B - NIPSCO - Concent Decree
Attachment C - NSPS 40 CFR 60, Subpart D
Attachment D - NSPS 40 CFR 60, Subpart Da
Attachment E - NSPS 40 CFR 60, Subpart Y
Attachment F - NSPS 40 CFR 60, Subpart GG
Attachment G - NESHAP 40 CFR 63, Subpart ZZZZ
Attachment H - NSPS 40 CFR 60, Subpart IIII
Appendix A - Acid Rain Permit

SECTION A SOURCE SUMMARY

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

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

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

Source Address:	Environmental, Health & Safety Department, 2723 East 1500 North, Wheatfield, Indiana 46392
General Source Phone Number:	219-647-5312
SIC Code:	4911
County Location:	Jasper
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

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

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

(a) One (1) cyclone coal-fired boiler identified as Unit 14, with construction commenced in 1970 and commercial operation begun in 1976, with a design heat input capacity of 4,650 million Btu per hour (MMBtu/hr), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter and exhausting to stack 14. Unit 14 has a selective catalytic reduction (SCR) system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 14 by 2014. The source plans to install and operate a Flue Gas Desulfurization System on Unit 14 by 2014.

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NO_X burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 15 by 2016. The source plans to install and operate a Selective Non-Catalytic Reduction (SNCR) system on Unit 15 by 2013 and a Flue Gas Desulfurization System on Unit 15 by 2016.

(c) One (1) dry bottom pulverized coal-fired boiler identified as Unit 17, with construction started in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 17 has been approved to fire blends of coal and petroleum coke.

(d) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, with construction started in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 18 has been approved to fire blends of coal and petroleum coke.

(e) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

(f) Coal storage and handling systems for Unit 14 and 15 boilers, constructed in 1972.

(1) Rail car unloading with wet suppression for PM control during unloading and enclosure for ancillary dust control.

(2) Coal pile unloading, coal storage pile(s), material handling equipment, and coal conveyors.

(3) Transfer House, with carryover wet suppression and enclosed transfer points within an enclosure for ancillary dust control, with an estimated throughput of 3,000 tons per hour.

(4) Crusher House, with carryover wet suppression for PM control and enclosed transfer points within an enclosure for ancillary dust control.

(5) Tripper House to tripper bays, with enclosed transfer points within an enclosure for dust control.

(6) Two (2) tripper bays with an estimated combined capacity of 3,000 tons per hour, with carryover wet suppression for PM control, each using an enclosure for ancillary dust control.

(g) Fuel storage and handling systems for Unit 17 and 18 boilers.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a multi-compartment baghouse for PM control.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) multi-compartment vent filters for PM control.

(h) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour.

(2) Two (2) ground limestone pneumatic truck unloading systems connected to Unit 17 limestone silos, with baghouses for PM control.

(3) Two (2) ground limestone pneumatic truck unloading systems connected to Unit 18 limestone silos, with baghouses for PM control.

(4) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour. All gypsum is handled wet.

(i) Dry fly ash handling and disposal.

(1) Pneumatic conveyance to storage silos, with a design capacity of 70 tons per hour of fly ash from Units 14 and 15 combined, and a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 14, 15, 17, and 18, with cyclone separators, silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads; and onsite disposal area.

(j) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(k) Ponded bottom ash handling/removal operations.

(l) Material handling for the flue gas desulfurization systems for Unit 14 and Unit 15 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Two (2) storage silos originally used for dual-alkali FGD system with cyclone separators, silo collector bag filters, and bin vent bag filters. Ground limestone pneumatic truck unloading systems for Unit 14 and Unit 15 limestone silos, with integrated bin vent filter, to begin construction in 2011.

(3) Two (2) new conveyors to begin construction in 2011 for transfer of dewatered gypsum from belt filters to junction house.

(4) Two (2) new conveyors to begin construction in 2011 for transfer of dewatered gypsum from junction house to the existing gypsum conveying system.

(5) Transportation of off-specification gypsum by truck on unpaved roads.

(6) Pneumatic lime unloading system and storage silo at the existing wastewater treatment plant.

(7) Lime Transport Truck traffic on paved roads.

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

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

(a) Conveyors as follows: [326 IAC 6-3]

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;

(2) 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;

(3) Uncovered coal conveying of less than or equal to 120 tons per day; and

(4) Underground conveyors.

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

(c) 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]

(d) Any of the following structural steel and bridge fabrication activities: [326 IAC 6-3]

(1) Cutting 200,000 linear feet or less of one inch (10) plate or equivalent.

(2) Using 80 tons or less of welding consumables.

(e) One (1) diesel-fired, compression-ignited, 334 horsepower engine for a stationary fire pump system, constructed before July 11, 2005. .[Under 40 CFR 60, Subpart IIII, emergency quench pumps are considered a new affected source]

(f) 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]

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

(1) Evaporation of Boiler Chemical Cleaning wastes.

(2) Coal pile wind erosion. [326 IAC 6-4]

(3) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill. [326 IAC 6-4]

(4) Shot blasters. [326 IAC 6-3]

(5) Gypsum stockpile. [326 IAC 6-3]

(6) Cold Cleaner degreasing operations. [326 IAC 8-3-2][326 IAC 8-3-5]

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

(h) Two (2) diesel fired-engines for emergency quench pumps (model year 2011), each rated at 144 horsepower, permitted in 2012.[Under 40 CFR 60, Subpart IIII, emergency quench pumps are considered a new affected source]

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

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

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

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

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

SECTION B GENERAL CONDITIONS

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

(a) 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) Notwithstanding B.1(a), the terms located in paragraphs of the Decree that are incorporated by reference into this permit in accordance with Section F and Attachment A shall have the definition, and only the definition, assigned to such terms in the Decree and are limited to Section F and Attachment A.

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

(a) This permit, T073-29983-00008, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

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

B.3 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

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

B.4 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.5 Severability [326 IAC 2-7-5(5)]

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

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

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

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

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

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

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

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

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(34), and

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

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

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

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

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

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

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

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

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

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

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

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

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

The Permittee shall implement the PMPs.

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

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

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

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

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

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.11 Emergency Provisions [326 IAC 2-7-16]

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

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

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

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

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

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, within four (4) daytime business hours after the beginning of the

emergency, or after the emergency was discovered or reasonably should have been discovered;

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

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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)(8) be revised in response to an emergency.

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

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

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

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

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

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

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

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

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

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

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

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

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

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

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

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

(a) All terms and conditions of permits established prior to T073-29983-00008 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

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

B.14 Reserved

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 Source Modification Requirement [326 IAC 2-7-10.5]

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

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

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

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

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

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

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

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

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

(a) No Part 70 permit revision 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.20 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

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

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

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

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

(4) The Permittee notifies the:

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

and

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

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

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

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

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(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 [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ, or U.S. EPA is required.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B.25 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.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

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

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

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

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

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

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

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

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

C.6 Reserved

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

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

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

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

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

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

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

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]

(a) 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.

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

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

C.12 Reserved

C.13 Reserved

C.14 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.15 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.16 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.17 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]

(l) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

(II)

(a) CAM *Response to excursions or exceedances.*

(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a QIP. The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:
(1) Failed to address the cause of the control device performance problems; or
(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*
(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(a)(2) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.
(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

C.18 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.19 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

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

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

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

The statement must be submitted to:

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

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

C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following:

(AA) All calibration and maintenance records.
(BB) All original strip chart recordings for continuous monitoring instrumentation.
(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.
(BB) The dates analyses were performed.
(CC) The company or entity that performed the analyses.
(DD) The analytical techniques or methods used.

(EE) The results of such analyses.

(FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

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

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(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 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or

326 IAC 2-3-1(jj)) 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(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), 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.21 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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) 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 (EUSGU), the Permittee shall submit a report to the department within sixty (60) days after the end of each year during which records must be generated under subdivision (3) [326 IAC 2-2-8(b)(3)] setting out the unit's annual emissions during the calendar year that preceded submission of the report.

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

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

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

(g) The report for project at an existing emissions unit shall be submitted no later than 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 projection.

Reports required in this part shall be submitted to:

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

(h) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for

review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

Stratospheric Ozone Protection

C.22 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.

Ambient Monitoring Requirements [326 IAC 7-3]

C.23 Ambient Monitoring [326 IAC 7-3]

(a) The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted to the commissioner for approval. The monitoring plan shall include requirements listed in 326 IAC 7-3-2(a)(1), 326 IAC 7-3-2(a)(2) and 326 IAC 7-3-2(a)(3).

(b) The Permittee and other operators subject to the requirements of this rule, located in the same county, may submit a joint monitoring plan to satisfy the requirements of this rule. [326 IAC 7-3-2(c)]

(c) The Permittee may petition the commissioner for an administrative waiver of all or some of the requirements of 326 IAC 7-3 if such owner or operator can demonstrate that ambient monitoring is unnecessary to determine continued maintenance of the sulfur dioxide ambient air quality standards in the vicinity of the source. [326 IAC 7-3-2(d)]

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) cyclone coal-fired boiler identified as Unit 14, with construction commenced in 1970 and commercial operation begun in 1976, with a design heat input capacity of 4,650 million Btu per hour (MMBtu/hr), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter and exhausting to stack 14. Unit 14 has a selective catalytic reduction (SCR) system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 14 by 2014. The source plans to install and operate a Flue Gas Desulfurization System on Unit 14 by 2014.

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

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

(1) Evaporation of Boiler Chemical Cleaning wastes.

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

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

D.1.1 Particulate Emission Requirements [326 IAC 6-2-1(g)]

Pursuant to 326 IAC 6-2-1(g) and Operation Permit 37-05-91-0102, issued on September 14, 1988, the particulate matter (PM) emissions to the atmosphere from the boiler identified as Unit 14 shall not exceed 0.1 pound per million Btu (lb/MMBtu) of energy input. The Permittee may request a permit revision to change the Unit 14 particulate limit to that required pursuant to 326 IAC 6-2-3, in accordance with 326 IAC 2-7-12, if accompanied by a demonstration that the National Ambient Air Quality Standards (NAAQS) are protected.

D.1.2 Startup, Shutdown, and Other Opacity Limits [326 IAC 5-1-3]

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

(1) When building a new fire in a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a cumulative total of one (1) hour (ten (10) six (6)-minute averaging periods) during the startup period, or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitator, whichever occurs first, provided, however, that once every three years opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a cumulative total of three (3) hours (thirty (30) six (6) minute averaging periods) during the startup period.

(2) When shutting down a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of one (1) hour (ten (10) six (6)-minute averaging periods) during the shutdown period.

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

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity 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 forty percent (40%) 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)]

(c) If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(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.

D.1.3 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 7.1.1-2(a)(3), sulfur dioxide emissions from Unit 14 shall not exceed 0.5 pounds per million Btu's (lb/MMBtu) when combusting only distillate oil or only distillate oil and natural gas.

(b) Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from Unit 14 shall not exceed six and zero-tenths (6.0) pounds per million Btu for coal combustion.

(c) Pursuant to 326 IAC 7-1.1-2(b), sulfur dioxide emissions from Unit 14 shall not exceed six and zero-tenths (6.0) pounds per million Btu when combusting coal and oil simultaneously.

D.1.4 Capacity Limitation [326 IAC 6-2-1(g)] [326 IAC 2-7-5]

Pursuant to 326 IAC 6-2-1(g) and Operation Permit 37-05-91-0102, issued on September 14, 1988, unit No. 14 shall not exceed a maximum hourly average of 468 megawatts gross until such time as stack testing indicates compliance with the PM and opacity limitations in Condition D.1.1 and Section C - Opacity at a higher level. The Permittee may request a temporary exemption in accordance with 326 IAC 2-1.1-3(g)(3) for stack testing at a higher capacity.

Compliance Determination Requirements

D.1.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

By December 31 of the second calendar year following the most recent stack test, compliance with the PM limitation for Unit 14 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 this 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.1.5.1 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

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

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

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

(d) 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 when plume conditions allow.

(1) When plume conditions allow, 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.

(2) When plume conditions allow 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 such time that a COMS is online.

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

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

(5) When plume conditions do not allow Method 9 visible emission readings, Permittee shall keep a record of the period during which such readings could not be taken and the reason why such readings could not be taken.

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

D.1.6 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator (ESP) for Unit 14 shall be operated at all times that coal is being combusted in Unit 14.

D.1.7 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems for Unit 14 shall be calibrated, maintained, and operated for measuring SO_2, and either CO_2 or O_2, which meet the performance specifications of 326 IAC 3-5-2.

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

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

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

D.1.8 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 SO_2 emission limits in Condition D.1.3 using a thirty (30) day rolling weighted average.

(b) 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 and other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

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

D.1.9 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

(b) Reasonable response steps shall be taken in accordance with Section C - Response to Excursions and Exceedances whenever the percentage of T-R sets in service falls below ninety percent (90%). T-R set failure resulting in less than ninety percent (90%) availability 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.1.10 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

(b) Opacity readings in excess of thirty percent (30%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps 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.

(c) The Permittee may request that the IDEM, OAQ approve a different opacity trigger level than the one specified in (a) and (b) of this condition, provided the Permittee can demonstrate, through stack testing or other appropriate means, that a different opacity trigger level is appropriate for monitoring compliance with the applicable particulate matter mass emission limits.

D.1.11 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

(a) Whenever both the primary and back-up SO_2 continuous emission monitoring systems (CEMS) are malfunctioning or down for repairs or adjustments, the following shall be used to provide information related to SO_2 emissions:

(1) If the CEMS is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(2) If the CEMS is down for twenty-four (24) hours or more:

(A) Either fuel sampling and fuel preparation and analysis shall be conducted in accordance with 326 IAC 3-7-2(b) and (c), 326 IAC 3-7-2 (d) and 326 IAC 3-7-2(e) or, alternatively, a portable analyzer, properly calibrated according to the manufacturer specifications (such as manufacturer operating or maintenance manuals), shall be used to monitor SO_2 emissions. To the extent the Permittee elects to conduct fuel sampling: the Permittee shall collect the coal sample as bunkered; coal shall be sampled at least three (3) times per day and at least one (1) time per eight (8) hour period unless no coal is bunkered during the preceding eight (8) hour period; and minimum sample size shall be five hundred (500) grams.

or

(B) Pursuant to 326 IAC 3-7-3, other manual and 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) To the extent the Permittee elects to conduct fuel sampling to comply with Condition D.1.11(a), 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 any information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4 under this Condition D.1.11. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

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

D.1.12 Record Keeping Requirements

(a) To document the compliance status with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.1.1, D.1.2, D.1.5, D.1.9, and D.1.10, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits in Conditions D.1.1, and D.1.2.

(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 COMS downtime.

(4) All ESP parametric monitoring readings pursuant to D.1.9.

(b) To document the compliance status with SO_2 Conditions D.1.3, D.1.8, and D.1.11, the Permittee shall maintain the records identified in (1) through (3) below. Records shall be complete and sufficient to establish compliance with the SO_2 limits as required in Conditions D.1.3 and D.1.8. The Permittee shall maintain records in accordance with (2) and (3) 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) Any fuel sampling and analysis data collected for or portable analyzer data for SO_2 CEM downtime, in accordance with Condition D.1.11.

(3) Actual fuel usage during each SO_2 CEM downtime to the extent such data is required by Condition D.1.11 to be obtained.

(c) To document the compliance status with Condition D.1.4, the Permittee shall maintain records of the Unit 14 gross output, in gross MW per hour.

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

D.1.13 Reporting Requirements

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document compliance status with Conditions D.1.1, D.1.3, D.1.4, and D.1.7 shall be submitted not later than thirty (30) days after the end of the calendar quarter being reported. 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.

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

(1) Date of downtime.

(2) Time of commencement.

(3) Duration of each downtime.

(4) Reasons for each downtime.

(5) Nature of system repairs and adjustments.

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

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NO_X burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 15 by 2016. The source plans to install and operate a Selective Non-Catalytic Reduction (SNCR) system on Unit 15 by 2013 and a Flue Gas Desulfurization System on Unit 15 by 2016.

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

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

(1) Evaporation of Boiler Chemical Cleaning wastes.

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

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

D.2.1 CO PSD BACT Requirements [326 IAC 2-2-3]

After completion of the LNB project and resumption of regular operation for unit 15 and a reasonable shakedown period not to exceed one hundred and eighty (180) days, the Permittee shall comply with the following requirements:

(a) CO emissions from Unit 15 shall not exceed 1.63 lb/MMBtu based on a 3-hour average.

(b) CO emissions from Unit 15 shall be minimized through the use of good combustion practices according to the Boiler Combustion Optimization Plan.

D.2.2 Reserved

D.2.3 Startup, Shutdown, and Other Opacity Limits [326 IAC 5-1-3]

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

(a) When building a new fire in a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of two (2) hours (twenty (20) six (6)-minute averaging periods) during the startup period, or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitation, whichever occurs first.

(b) When shutting down a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of two (2) hours (twenty (20) six (6)-minute averaging periods) during the shutdown period.

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

D.2.4 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 7.1.1-2(a)(3), sulfur dioxide emissions from Unit 15 shall not exceed five-tenths (0.5) pound per million Btu's (lb/MMBtu) when combusting only distillate oil or only distillate oil and natural gas.

(b) Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from Unit 15 shall not exceed six and zero-tenths (6.0) pounds per million Btu for coal combustion.

(c) Pursuant to 326 IAC 7-1.1-2(b), sulfur dioxide emissions from Unit 15 shall not exceed six and zero-tenths (6.0) pounds per million Btu when combusting coal and oil simultaneously.

D.2.5 Reserved

Compliance Determination Requirements

D.2.6 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) By December 31 of the second calendar year following the most recent stack test, compliance with the CO limitation in Condition D.2.1 shall be determined by a performance stack test conducted using methods approved by the Commissioner. This testing shall be repeated by December of every fifth calendar year following this 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.

(b) By December 31 of the second calendar year following the most recent stack test, compliance with the PM limitation in Condition D.2.2 shall be determined by a performance stack test conducted using Method 5 or other methods as approved by the Commissioner. This testing shall be repeated by December of every second calendar year following this 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.2.6.1 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

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

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

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

(d) 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 when plume conditions allow.

(1) When plume conditions allow, 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.

(2) When plume conditions allow 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 such time that a COMS is online.

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

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

(5) When plume conditions do not allow Method 9 visible emission readings, Permittee shall keep a record of the period during which such readings could not be taken and the reason why such readings could not be taken.

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

D.2.7 Boiler Combustion Optimization Plan [326 IAC 2-2]

NIPSCO shall develop and implement a Boiler Combustion Optimization Plan within 120 days of the startup date of Unit 15 after the unit outage for the low-NO_X Burner project. This plan will identify boiler operating parameters that indicate good combustion practices consistent with the BACT determination for Unit 15. NIPSCO will monitor operating parameters for Unit 15 consistent with this plan to demonstrate compliance with the BACT emission limit.

D.2.8 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator (ESP) shall be operated at all times that the boiler vented to the ESP is in operation.

D.2.9 Continuous Emissions Monitoring (CEMS) [326 IAC 2-2] [326 IAC 3-5] [326 IAC 12] [40 CFR 60, Subpart D]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 40 CFR 60.45, continuous emission monitoring systems for Unit 15 shall be calibrated, maintained, and operated for measuring SO_2, NO_X and either O_2 or CO_2, which meet the performance specifications of 326 IAC 3-5-2 and 40 CFR 60.45.

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

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

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

D.2.10 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(a) and (c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of five-tenths (0.5) pound per MMBtu when combusting distillate oil or distillate oil and natural gas using a thirty (30) day rolling weighted average.

(b) 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 and the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

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

D.2.11 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

(b) Reasonable response steps shall be taken in accordance with Section C - Response to Excursions and Exceedances whenever a total of more than four (4) T-R sets are

not in service. T-R set failure resulting in a response step obligation under the preceding sentence 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.2.12 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever both the primary and back-up SO_2 continuous emission monitoring systems (CEMS) are malfunctioning or down for repairs or adjustments, the following shall be used to provide information related to SO_2 emissions:

(a) If the CEMS is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(b) If the CEMS is down for twenty-four (24) hours or more:

(1) Either fuel sampling and fuel preparation and analysis shall be conducted in accordance with 326 IAC 3-7-2(b) and (c), 326 IAC 3-7-2(d) and 326 IAC 3-7-2(e) or, alternatively, a portable analyzer, properly calibrated according to manufacturer specifications (such as manufacturer operating or maintenance manuals), shall be used to monitor SO_2 emissions. To the extent the Permittee elects to conduct fuel sampling: the Permittee shall collect the coal sample as bunkered; coal shall be sampled at least three (3) times per day and at least one (1) time per eight (8) hour period unless no coal is bunkered during the preceding eight (8) hour period; and minimum sample size shall be five hundred (500) grams

or

(2) Pursuant to 326 IAC 3-7-3, other manual and 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.

(c) To the extent the Permittee elects to conduct fuel sampling to comply with Condition D.2.10(a), 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 any information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4 under this Condition D.2.10. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

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

D.2.13 Record Keeping Requirements

(a) To document the compliance status with the carbon monoxide requirements in Condition D.2.1 and D.2.6(a), the Permittee shall maintain records on-site in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the limit in Condition D.2.1.

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

(2) Boiler Combustion Optimization Plan.

(b) To document the compliance status with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.2.3, D.2.6(b), D.2.8, and D.2.11, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits in Condition D.2.3.

(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 COMS downtime.

(4) All ESP parametric monitoring readings pursuant to condition D.2.11.

(c) To document the compliance status with the SO_2 requirements in Conditions D.2.4, D.2.9, D.2.10, and D.2.12, the Permittee shall maintain the records identified in (1) through (3) below. Records shall be complete and sufficient to establish compliance with the applicable SO_2 limit(s) as required in Conditions D.2.4, and D.2.10. The Permittee shall maintain records in accordance with (2) and (3) 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) Any fuel sampling and analysis data collected for or portable analyzer data for SO_2 CEM downtime, in accordance with Condition D.2.12.

(3) Actual fuel usage during each SO_2 CEM downtime to the extent such data is required by Condition D.2.12 to be obtained.

(d) To document the compliance status with the NO_X requirements, the continuous emissions monitoring requirements for NO_X and CO_2 or O_2 in Condition D.2.9, 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. Records shall be complete and sufficient to establish compliance with the NO_X limit as required in Condition D.2.9.

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

D.2.14 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, D.2.3, D.2.4, D.2.9, D.2.10, D.2.11, and D.2.12, shall be submitted not later than thirty (30) days after the end of the calendar quarter being reported. 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.

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

(1) Date of downtime.

(2) Time of commencement.

(3) Duration of each downtime.

(4) Reasons for each downtime.

(5) Nature of system repairs and adjustments.

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

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) dry bottom pulverized coal-fired boiler identified as Unit 17, with construction started in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 17 has been approved to fire blends of coal and petroleum coke.

(d) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, with construction started in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 18 has been approved to fire blends of coal and petroleum coke.

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

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

(1) Evaporation of Boiler Chemical Cleaning wastes.

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

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

D.3.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2] [326 IAC 6-2-1(g)] [326 IAC 7-1.1-2]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1460, issued April 14, 1980:

(a) Each boiler unit (Units 17 and 18) shall not be operated in excess of 3,967 MMBtu per hour heat input. (in EPA-5-A-80-18 only)

(b) Stack gas particulate emissions shall be controlled to 0.03 pound or less of total suspended particulates per million BTU (lb/MMBtu) of heat input to comply with the NSPS.

This requirement will be met by using electrostatic precipitators (ECP) which will provide a 99.8 percent guaranteed control efficiency. (in PC (37) 1460 only)

(c) The opacity of the exhaust gases shall not exceed twenty percent (20%) based on a six-minute average except for one six-minute period per hour of opacity not exceeding twenty-seven percent (27%). (EPA 5-A-80-18 only)

(d) Stack gas sulfur dioxide emissions from each unit shall not exceed 0.62 pound per million BTU (lb/MMBTU) of heat input. A 90 percent reduction in potential SO_2 emissions is required, as determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

(e) Nitrogen oxide emissions from each boiler shall not exceed 0.6 pound per million BTU (lb/MMBTU) of heat input.

(f) The Permittee shall continue to operate the existing meteorological and air quality sampling network for SO_2. [326 IAC 2-2-4(c)(5) and (6)] (in PC (37) 1460 only)

D.3.2 Reserved

D.3.3 Alternative Fuel Blends [326 IAC 2-2]

(a) Pursuant to a letter from IDEM, OAQ, to NIPSCO dated June 13, 1996, based on the results of emissions testing performed in 1995 and subsequent ambient air modeling studies, petroleum coke may be combusted in Units 17 and 18 at a blend rate of no more than 30 percent (30%) petroleum coke (by weight). The conditions of the Units 17 and 18 federal PSD construction permit are not affected by this ruling, and all requirements contained therein still apply.

(b) The flue gas desulfurization (FGD) system shall be in operation at all times when pet coke is being fired. Should an emergency condition occur which causes a malfunction of the FGD system, the Permittee shall cease bunkering pet coke until the FGD system is fully operational.

D.3.4 Reserved

Compliance Determination Requirements

D.3.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

By December 31 of the second calendar year following the most recent stack test, compliance with the PM limitation in Condition D.3.1 shall be determined by a performance stack test conducted using Method 5B or 17, or other methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following this 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.3.5.1 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

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

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

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

(d) 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 when plume conditions allow.

(1) When plume conditions allow, 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.

(2) When plume conditions allow 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 such time that a COMS is online.

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

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

(5) When plume conditions do not allow Method 9 visible emission readings, Permittee shall keep a record of the period during which such readings could not be taken and the reason why such readings could not be taken.

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

D.3.6 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator (ESP) shall be operated at all times that the corresponding boiler is in operation.

D.3.7 Scrubber Operation [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with all applicable SO_2 emission limits.

D.3.8 Reserved

D.3.9 Continuous Emissions Monitoring [326 IAC 2-2] [326 IAC 3-5] [326 IAC 7-2-1(g)] [326 IAC 12] [40 CFR 60, Subpart Da]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), 40 CFR 60 Subpart Da, Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued April 14, 1980, and 326 IAC 2-2, continuous emission monitoring systems for Units 17 and 18 shall be calibrated, maintained, and operated for measuring opacity, SO_2, NO_X, and either CO_2 or O_2, which meet all applicable performance specifications of 326 IAC 3-5-2.

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

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

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

D.3.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3]

The Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the limits in Condition D.3.1(d), as established in PSD Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Construction Permit PC (37) 1460, issued April 14, 1980, using a thirty (30) day rolling arithmetic average in the same manner as is required under D.3.8(g).

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

D.3.11 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

(b) Reasonable response steps shall be taken in accordance with Section C - Response to Excursions and Exceedances whenever a total of more than three (3) T-R sets at Unit 17 or a total of more than two (2) T-R sets at Unit 18 are not in service. T-R set failure resulting in a response step obligation under the preceding sentence 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.3.12 SO_2 Monitoring System Downtime [326 IAC 2-2] [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever both the primary and back-up SO_2 continuous emission monitoring systems (CEMS) are malfunctioning or down for repairs or adjustments for a period of twenty-four (24) hours or more, the Permittee shall monitor and record boiler load, recirculation pH, slurry valve position, and absorber level to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

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

D.3.13 Record Keeping Requirements

(a) To document the compliance status with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.3.1, D.3.9, and D.3.11 the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits in Conditions D.3.1.

(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 COMS downtime.

(4) All ESP parametric monitoring readings pursuant to condition D.3.11.

(b) To document the compliance status with SO_2 Conditions D.3.1(d), D.3.9, D.3.10, and D.3.12, 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 limit(s) as required in Conditions D.3.1(d), D.3.9, D.3.10, and D.3.12. The Permittee shall maintain records in accordance with (2) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g) and/or 40 CFR 60.47a.

(2) All scrubber parametric monitoring readings taken during any periods of CEM downtime, in accordance with Condition D.3.12.

(c) To document the compliance status with NO_X Conditions D.3.1(e) and D.3.9, 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 and 326 IAC 2-2. Records shall be complete and sufficient to establish compliance with the NO_X limits as required in Conditions D.3.1(e) and D.3.9.

(d) To document the compliance status with the ambient monitoring requirements of Condition D.3.1(f), the Permittee shall maintain records of the meteorological and SO_2 readings.

(e) To document the compliance status with Condition D.3.3, the Permittee shall maintain records of the amount of petroleum coke combusted and the pet coke/coal blend rate for each boiler. Records shall be complete and sufficient to establish compliance with the fuel limit of Condition D.3.3 using a thirty (30) day rolling weighted average.

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

D.3.14 Reporting Requirements

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document the compliance status with Conditions D.3.1 and D.3.3 shall be submitted not later than thirty (30) days after the end of the calendar quarter being reported. 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.

(b) The Permittee shall report the air quality and meteorological data required by Condition D.3.1(f) in a format specified by the commissioner within ninety (90) days after the end of each calendar quarter.

(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.

(5) Nature of system repairs and adjustments.

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

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

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

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

D.4.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-79-A-25, issued on August 16, 1979, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1380, issued May 9, 1979:

(a) Nitrogen oxide (NO_X) emissions from each turbine shall not exceed 93 ppm at 15% oxygen on a dry basis.

(b) Each turbine unit shall not operate in excess of 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

D.4.2 Reserved

D.4.3 Opacity [326 IAC 5-1]

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

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

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

D.4.4 Reserved

Compliance Determination Requirements

D.4.5 NOx Control

To the extent necessary to comply with Condition D.4.1, the water injection systems which are used to control the NOx emissions from turbines 16A and 16B shall be in operation and control emissions from turbines 16A and 16B.

D.4.6 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 326 IAC 2-2 (PSD), the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring NOx and O_2 emissions rates from the combustion turbine stacks in accordance with 326 IAC 3-5 to demonstrate compliance with Condition D.4.1(a).

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

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

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

D.4.7 Reserved

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

D.4.8 Record Keeping Requirements

(a) To document the compliance status with Conditions D.4.1(a) and D.4.6, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the nitrogen oxides (NO_X) and sulfur dioxide (SO_2) limits established in Conditions D.4.1(a).

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

(2) To document the compliance status with Condition D.4.6, the Permittee shall maintain records of:

(i) All continuous monitoring system data of fuel consumption and the ratio of water to fuel being fired; or

(i) All continuous emission monitoring system (CEMS) data of NO_x and O_2 whenever Permittee elects to use CEMS to monitor NO_x and O_2.

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall maintain records of the date and times for all periods of turbine operation.

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

D.4.9 Reporting Requirements

(a) To document the compliance status with Condition D.4.1(a), the Permittee shall submit a quarterly summary of :

(1) The ratio of water to fuel if using the continuous monitoring method outlined in 40 CFR 60, Subpart GG; or

(2) The NO_x emissions if using the continuous emissions monitoring method outlined in Condition D.4.6.

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

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall submit a quarterly summary of the hours of operation for each combustion turbine. These reports shall be submitted to the address listed in Section C - General Reporting Requirements, of this approval. 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

Emissions Unit Description:

(f) Coal storage and handling systems for Unit 14 and 15 boilers constructed in 1972.

(1) Rail car unloading with wet suppression for PM control during unloading and enclosure for ancillary dust control.

(2) Coal pile unloading, coal storage pile(s), material handling equipment, and coal conveyors.

(3) Transfer House, with carryover wet suppression and enclosed transfer points within an enclosure for ancillary dust control, with an estimated throughput of 3,000 tons per hour.

(4) Crusher House, with carryover wet suppression for PM control and enclosed transfer points within an enclosure for ancillary dust control.

(5) Tripper House to tripper bays, with enclosed transfer points within an enclosure for dust control.

(6) Two (2) tripper bays with an estimated combined capacity of 3,000 tons per hour, with carryover wet suppression for PM control, each using an enclosure for ancillary dust control.

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

(a) Conveyors as follows [326 IAC 6-3]:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;

(3) Uncovered coal conveying of less than or equal to 120 tons per day.

(4) Underground conveyors.

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

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

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

D.5.1 Particulate Emission Limitation for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), allowable particulate emissions for the coal handling operations shall be calculated as follows:

(a) Particulate shall not be emitted in excess of the amount shown in the table in 326 IAC 6-3-2(e). The allowable rate of emission shall be based on the process weight rate for the process.

(b) Interpolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates 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.

(c) Interpolation and extrapolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

E = 55.0 P 0.11 – 40 where E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour.

(d) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emission may exceed that shown in the table in 326 IAC 6-3-2(e), provided the concentration of particulate in the discharge gases to the atmosphere is less than one-tenth (0.10) pound per one thousand (1,000) pounds of gases.

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) Fuel storage and handling systems for Unit 17 and 18 boilers.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a multi-compartment baghouse for PM control.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) multi-compartment vent filters for PM control.

<u>Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:</u>

(a) Conveyors as follows [326 IAC 6-3]:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;

(3) Uncovered coal conveying of less than or equal to 120 tons per day; and

(4) Underground conveyors.

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

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

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

D.6.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

(a) Particulate emissions from coal unloading shall not exceed ten percent (10%) opacity for the duration of the unloading operation.

(b) All coal conveyors shall be completely enclosed.

(c) All transfer points shall be completely enclosed except those at the storage pile.

(d) Particulate emissions from the crusher house, conveyor room and reclaim tunnels shall be controlled to 99 percent.

(e) Fugitive emissions from the coal piles shall be minimized by compaction and other appropriate measures (surfactant spray etc.).

D.6.2 Reserved

D.6.3 Particulate Emission Limitation for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), for the fuel storage and handling systems for Units 17 and 18 other than the coal storage piles, allowable particulate emissions for the coal handling operations shall be calculated as follows:

(a) Particulate shall not be emitted in excess of the amount shown in the table in 326 IAC 6-3-2(e). The allowable rate of emission shall be based on the process weight rate for the process.

(b) Interpolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates 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.

(c) Interpolation and extrapolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

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

(d) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emission may exceed that shown in the table in 326 IAC 6-3-2(e), provided the concentration of particulate in the discharge gases to the atmosphere is less than one-tenth (0.10) pound per one thousand (1,000) pounds of gases.

D.6.4 Reserved

Compliance Determination Requirements

D.6.5 Particulate Control [326 IAC 2-7-6(6)]

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 bag will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed bag will be repaired or replaced. The notification shall also include the results of any response actions taken up to the time of notification.

D.6.6 Reserved

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

D.6.7 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

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

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

(d) If abnormal emissions of dust are observed from the rail car unloading station openings, the fuel transfer exhaust points, or the coal crusher exhaust, the Permittee shall take reasonable response steps. Observation of abnormal visible emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or 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.

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

(f) 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.

(g) 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.

D.6.8 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) The Permittee shall record the pressure drop across the baghouse used in conjunction with the coal crusher at least once per week when the coal crusher is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 2.0 and 8.0 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 Permittee shall record the pressure drop across each of the baghouses used in conjunction with the fuel transfer points at least once per week when fuel is being transferred. When for any one reading, the pressure drop across the baghouse is outside the normal range of 2.0 and 8.0 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.

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

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

D.6.9 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.7 - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the coal unloading station openings, coal transfer exhaust points, and crusher baghouse exhaust. 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.6.8 - Parametric Monitoring, the Permittee shall maintain the daily records of the pressure drop across the baghouse controlling the rail car unloading coal and the two tripper conveyors. 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

Emissions Unit Description:

(h) Material handling for the flue gas desulfurization systems for Units 17 and 18, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour.

(2) Two (2) ground limestone pneumatic truck unloading systems connected to Unit 17 limestone silos, with baghouses for PM control.

(3) Two (2) ground limestone pneumatic truck unloading systems connected to Unit 18 limestone silos, with baghouses for PM control.

(4) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour. All gypsum is handled wet.

(I) Material handling for the flue gas desulfurization systems for Unit 14 and Unit 15 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Ground limestone pneumatic truck unloading systems for Unit 14 and Unit 15 limestone silos, with integrated bin vent filter, to begin construction in 2011.

(3) Two (2) new conveyors to begin construction in 2011 for transfer of dewatered gypsum from belt filters to junction house.

(4) Two (2) new conveyors to begin construction in 2011 for transfer of dewatered gypsum from junction house to the existing gypsum conveying system.

(5) Transportation of off-specification gypsum by truck on unpaved roads.

(6) Pneumatic lime unloading system and storage silo at the existing wastewater treatment plant.

(7) Lime Transport Truck traffic on paved roads.

<u>Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:</u>

(a) Conveyors as follows [326 IAC 6-3]:

(2) 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;

(4) Underground conveyors.

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

(5) Gypsum stockpile [326 IAC 6-3].

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

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

D.7.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the limestone handling systems and gypsum transfer systems shall not exceed 30 pounds per hour, each, when operating at a process weight rate of 38,941 pounds per hour. This pounds per hour limitation was calculated using the following equation:

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.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(i) Dry fly ash handling and disposal.

(1) Pneumatic conveyance to storage silos, with a design capacity of 70 tons per hour of fly ash from Units 14 and 15 combined, and a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 14, 15, 17, and 18, with cyclone separators, silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Two (2) storage silos originally used for dual-alkali FGD system, currently used for storage of fly ash from Unit 15; with cyclone separators, silo collector bag filters, and bin vent bag filters; with telescoping chute unloaders with vacuum line to the silo for dry ash unloading to enclosed trucks.

(4) Transportation by truck via in-plant haul roads; and onsite disposal area.

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

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

D.8.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2]

For the fly ash from Units 17 and 18, pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

Fly ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. Trucks utilized for dry or unconditioned ash disposal shall be covered. (in EPA-5-A-80-18 only)

D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the fly ash conveyance from Units 14 and 15 shall not exceed 47.8 pounds per hour when operating at a process weight rate of 70 tons per hour of ash, and the particulate emission rate from the fly ash conveyance from each of Units 17 and 18 shall not exceed 46.8 pounds per hour when operating at a process weight rate of 63 tons per hour of fly ash from each of Units 17 and 18. These pounds per hour limitations were calculated using the following equation:

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

$E = 55.0\ P^{0.11} - 40$

Where:

E = rate of emission in pounds per hour; and

P = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for dry fly ash silo unloading at a throughput rate greater than 200 tons per hour, 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.

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

D.8.3 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the ash silo unloading station openings shall be performed at least once per day during normal daylight operations when ash is being unloaded. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the fly ash conveyance and silo bag filter and bin vent filter exhausts shall be performed at least once per day during normal daylight operations when transferring ash to the corresponding silo. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the nozzle of each telescoping chute shall be performed at least once per day during normal daylight operations when unloading ash through the chute. A trained employee shall record whether emissions are normal or abnormal.

(d) If abnormal visible emissions of ash are observed from the ash silo unloading station openings, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions and Exceedances. Observation of abnormal visible emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions and Exceedances, shall be considered a deviation from this permit.

(e) If abnormal emissions are observed at any bag filter exhaust, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions and Exceedances. Observation of abnormal emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions and Exceedances, shall be considered a deviation from this permit.

(f) 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.

(g) 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.

(h) 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.

D.8.4 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) The Permittee shall record the pressure drop across the bag filters used in conjunction with the ash handling at least once per day 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 12.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions and Exceedances. A pressure drop reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions and Exceedances, 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 in accordance with the manufacturer's specifications. The specifications shall be available on site with the Preventive Maintenance Plan.

D.8.5 Broken or Failed Bag Detection [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

In the event that bag failure has been observed:

For bin vent filters, if failure is indicated by an opacity violation, or if filter failure is determined by other means, such as gas temperatures, flow rates, air infiltration, leaks, dust traces or triboflows, then failed unit and the associated process will 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).

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

D.8.6 Record Keeping Requirements

(a) To document the compliance status with Condition D.8.3 - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the Unit 17 and 18 ash silo unloading station openings, and the Unit 17 and 18 baghouse stack exhaust. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.8.4 - Parametric Monitoring, the Permittee shall maintain the daily records of the pressure drop across the baghouse controlling the dry fly ash handling and disposal. 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.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(j) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(k) Ponded bottom ash handling/removal operations.

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

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

(3) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill. [326 IAC 6-4]

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

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

D.9.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued April 14, 1980, with respect to Units 17 and 18:

(a) The bottom ash shall be sluiced to waste disposal ponds. (in PC (37) 1460 only)

(b) Bottom ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. (in EPA-5-A-80-18 only)

D.9.2 Reserved

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

D.9.3 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of any active onsite landfill area(s) shall be performed at least once per day during normal daylight operations. Any storage pond in the Waste Disposal Area or the Material Storage Runoff Pond area that contains either bottom ash and/or FGD sludge shall be observed once per week to determine if sufficient water is present in the pond to cover or saturate bottom ash and/or sludge deposited in the pond. During

any period when there is not sufficient water in the pond to cover or saturate bottom ash and/or sludge present in the pond, visible emission notations of such storage pond area(s) shall be performed at least once per day during normal daylight operations. When daily visible emission notations are made, a trained employee shall record whether emissions are normal or abnormal.

(b) If visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions and Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions and Exceedances, shall be considered a deviation from this permit.

(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.

(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.

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

D.9.4 Record Keeping Requirements

(a) To document the compliance status with Condition D.9.3 - Visible Emission Notations, the Permittee shall maintain records of visible observations, and any resulting visible emission notations of the Waste Disposal Area and the Material Storage Runoff Pond area, and records of visible emission notations relating to any active onsite landfill area(s).The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

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

SECTION D.10 **Reserved**

Emissions Unit Description:

Reserved

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

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

(c) 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]

(d) Any of the following structural steel and bridge fabrication activities: [326 IAC 6-3]

(1) Cutting 200,000 linear feet or less of one inch (10) plate or equivalent.

(2) Using 80 tons or less of welding consumables.

(f) 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]

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day: [326 IAC 6-3]

(4) Shot blasters. [326 IAC 6-3]

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

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

D.11.1 Particulate Emission Limitations for Manufacturing Processes [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 and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), 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:

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.

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

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

(6) Cold cleaner degreasing operations. [326 IAC 8-3-2][326 IAC 8-3-5]

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

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

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

D.12.1 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°C) (one hundred degrees Fahrenheit (100°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°C) (one hundred degrees Fahrenheit (100°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°C) (one hundred degrees Fahrenheit (100°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°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 E.1 TITLE IV CONDITIONS

ORIS Code: 6085

Emissions Unit Description:

(a) One (1) cyclone coal-fired boiler identified as Unit 14, with construction commenced in 1970 and commercial operation begun in 1976, with a design heat input capacity of 4,650 million Btu per hour (MMBtu/hr), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter and exhausting to stack 14. Unit 14 has a selective catalytic reduction (SCR) system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 14 by 2014. The source plans to install and operate a Flue Gas Desulfurization System on Unit 14 by 2014.

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NO_X burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 15 by 2016. The source plans to install and operate a Selective Non-Catalytic Reduction (SNCR) system on Unit 15 by 2013 and a Flue Gas Desulfurization System on Unit 15 by 2016.

(c) One (1) dry bottom pulverized coal-fired boiler identified as Unit 17, with construction started in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBTU/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 17 has been approved to fire blends of coal and petroleum coke.

(d) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, with construction started in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBTU/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 18 has been approved to fire blends of coal and petroleum coke.

(e) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

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

Acid Rain Program

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

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78. The Acid Rain permit for this source is attached to this permit as Appendix A (The Acid rain permit has expired, therefore, this attachment is not included with this permit), and is incorporated by reference.

E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)][326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(1) One (1) dry bottom pulverized coal-fired boiler identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NO_X burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 15 by 2016. The source plans to install and operate a Selective Non-Catalytic Reduction (SNCR) system on Unit 15 by 2013 and a Flue Gas Desulfurization System on Unit 15 by 2016.

(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]

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

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

E.2.2 Standards of Performance for Fossil-Fuel-Fired Steam Generators [40 CFR Part 60, Subpart D] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart D, the Permittee shall comply with the provisions of the Standards of Performance for Fossil-Fuel-Fired Steam Generators, which are incorporated by reference as 326 IAC 12, for the dry bottom pulverized coal-fired boiler identified as Unit 15 as specified as follows:

(1) 40 CFR 60.40(a) & (c)
(2) 40 CFR 60.42(a)
(3) 40 CFR 60.43(a), (b) & (c)
(4) 40 CFR 60.44(a)(1-3)&(b)
(5) 40 CFR 60.45
(6) 40 CFR 60.46

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(1) One (1) dry bottom pulverized coal-fired boiler identified as Unit 17, with construction started in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 17 has been approved to fire blends of coal and petroleum coke.

(2) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, with construction started in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 18 has been approved to fire blends of coal and petroleum coke.

(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]

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

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

E.3.2 Standards of Performance for Electric Utility Steam Generating Units [40 CFR Part 60, Subpart Da] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Da, the Permittee shall comply with the provisions of the Standards of Performance for Electric Utility Steam Generating Units, which are incorporated by reference as 326 IAC 12, for the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18 as specified as follows:

(1) 40 CFR 60.40da(a)
(2) 40 CFR 60.42da(a)&(b)
(3) 40 CFR 60.43da(a),(b),&(h)
(4) 40 CFR 60.44da(a)
(5) 40 CFR 60.48da(a),(b),(d),(e),(h),(q),&(s)
(6) 40 CFR 60.49da(a)(1),(b)(1),(b)(4),(c),(d),(e),(f)(1),(g),(h),(i),(j),(s),&(w)

(7) 40 CFR 60.50da(a).(b)(1),(b)(3),(c),(d),&(e)
(8) 40 CFR 60.51da(a),(b),(c),(i),(j),&(k)

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(1) Fuel storage and handling systems for Unit 17 and 18 boilers.

(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]

E.4.1 General Provisions Relating to New Source Performance Standards [326 IAC 12] [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 enclosed coal crushers, except as otherwise specified in 40 CFR Part 60, Subpart Y.

E.4.2 New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements [40 CFR Part 60, Subpart Y] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Y, the Permittee shall comply with the provisions of New Source Performance Standards for Coal Preparation and Processing Plants, which are incorporated by reference as 326 IAC 12, for the above emission units as specified as follows:

(1) 40 CFR 60.250(a)&(b)
(2) 40 CFR 60.254(a)
(3) 40 CFR 60.255(a)

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(1) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

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

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the two (2) natural gas combustion turbines 16A and 16B, except as otherwise specified in 40 CFR Part 60, Subparts GG.

E.5.2 New Source Performance Standards for Stationary Gas Turbines Requirements [40 CFR Part 60, Subpart GG] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart GG, the Permittee shall comply with the provisions of New Source Performance Standards for Stationary Gas Turbines, which are incorporated by reference as 326 IAC 12, for the two (2) natural gas combustion turbines 16A and 16B as specified as follows:

(1) 40 CFR 60.330
(2) 40 CFR 60.332(a)&(f)
(3) 40 CFR 60.333
(4) 40 CFR 60.334
(5) 40 CFR 60.335

SECTION E.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(h) Two (2) diesel fired-engines for emergency quench pumps (model year 2011), each rated at 144 horsepower, permitted in 2012.[Under 40 CFR 60, Subpart IIII, emergency quench pumps are considered a new affected source].

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

New Source Performance Standards (NSPS) [40 CFR Part 60]

E.6.1 General Provisions Relating to New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the emergency engine described in this section except when otherwise specified in Table 8 to 40 CFR Part 60, Subpart IIII.

E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [326 IAC 12] [40 CFR Part 60, Subpart IIII]

The Permittee shall comply with the following provisions of 40 CFR 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines), which are incorporated as specified as follows:

(1) 40 CFR 60.4200(a)(2)(ii);
(2) 40 CFR 60.4205(c);
(3) 40 CFR 60.4206;
(4) 40 CFR 60.4207(a);
(5) 40 CFR 60.4207(b);
(6) 40 CFR 60.4209(a);
(7) 40 CFR 60.4211(a);
(8) 40 CFR 60.4211(c);
(9) 40 CFR 60.4211(f);
(10) 40 CFR 60.4211(g)(2);
(11) 40 CFR 60.4214(b);
(12) 40 CFR 60.4218;
(13) Table 3 to Subpart IIII of Part 60
(14) Table 4 to Subpart IIII of Part 60
(15) Table 8 to Subpart IIII of Part 60

SECTION E.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) One (1) diesel-fired, compression-ignited, 334 horsepower engine for a stationary fire pump system. It was constructed before July 11, 2005.

(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]

E.7.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for stationary reciprocating Internal Combustion Engines [326 IAC 20] [40 CFR Part 63, Subpart A]

Pursuant to 40 CFR 63.6590, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 for the affected source, as specified in Appendix A of 40 CFR Part 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR 63 Subpart ZZZZ.

E.7.2 National Emissions Standard for Hazardous Air Pollutants for stationary reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ]

Pursuant to CFR Part 63, Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR Part 63.6590, for the affected source, as specified as follows:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(1)(ii),(b)(3)(iii),&(c)(7)
(4) 40 CFR 63.6595(a)(1)
(5) 40 CFR 63.6602
(6) 40 CFR 63.6605
(7) 40 CFR 63.6625(e),(f),(h),&(i)
(8) 40 CFR 63.6640(f)
(9) 40 CFR 63.6645(a)(1)&(a)(5)
(10) 40 CFR 63.6655(d),(e)(2),&(f)(1)
(11) 40 CFR 63.6660
(12) 40 CFR 63.6665
(13) Table 2(c), #1, of Subpart ZZZZ of Part 63
(14) Table 6, #9, of Subpart ZZZZ of Part 63

SECTION F. EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

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

Provisions of NIPSCO Consent Decree Applicable to Schahfer Generating Station

F.1 Consent Decree [*United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011), paragraph 169] [326 IAC 2-7-6(3)]

This source is subject to certain conditions, requirements and limitations set forth in the consent decree entered into by and among the United States, the State of Indiana, and the Permittee in *United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011) (herein referred to as the "Decree"). Pursuant to paragraph 169 of the Decree, those paragraphs and tables of the Decree listed in Attachment A of this permit are incorporated by reference into this permit and are applicable requirements under this permit. Subject to the terms and conditions of this Section F.1, the Permittee shall comply with the paragraphs and tables of the Decree that are listed in Attachment A of this permit. A copy of the Decree is attached to this permit as Attachment B. However, only those specific paragraphs and tables of the Decree that are included in Attachment A of this permit and incorporated by reference pursuant to this Section F.1, are applicable requirements enforceable through this permit.

Each paragraph and table listed in Attachment A of this permit is incorporated by reference in its entirety, including any and all paragraphs, conditions, requirements and/or limitations of the Decree explicitly referenced in such paragraphs or tables. However, the Permittee's obligations under this permit to comply with the conditions, requirements and limitations incorporated by reference in the paragraphs and tables listed in Attachment A of this permit shall be limited to those conditions, requirements and limitations applicable to, and only to the extent applicable to, the Schahfer Station while this permit is in effect. For clarity, such applicable conditions, requirements and limitations shall, subject to the subsequent paragraph, include the annual system tonnage limitations applicable to the NIPSCO System (as that term is defined under paragraph 36 of the Decree) as a whole as provided under Table 4 and Table 6 of the Decree as listed in Attachment A hereto.

In accordance with paragraph 169 of the Decree, any noncompliance with an annual system tonnage limitation incorporated by reference pursuant to this Section F.1 and Attachment A shall constitute a single violation for the NIPSCO System (as that term is defined under paragraph 36 of the Decree) as a whole and does not create a separate violation or violations for each unit or source within the NIPSCO System. Compliance with the paragraphs and tables listed in Attachment A of this permit shall be determined exclusively by reference to the conditions, requirements and limitations of the Decree. Whenever any conflict or inconsistency arises between the Decree and this permit, the terms and conditions of the Decree control.

SECTION G Clean Air Interstate Rule (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

ORIS Code: 6085

Emissions Unit Description:

(a) One (1) cyclone coal-fired boiler identified as Unit 14, with construction commenced in 1970 and commercial operation begun in 1976, with a design heat input capacity of 4,650 million Btu per hour (MMBtu/hr), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter and exhausting to stack 14. Unit 14 has a selective catalytic reduction (SCR) system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 14 by 2014. The source plans to install and operate a Flue Gas Desulfurization System on Unit 14 by 2014.

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NO_X burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 15 by 2016. The source plans to install and operate a Selective Non-Catalytic Reduction (SNCR) system on Unit 15 by 2013 and a Flue Gas Desulfurization System on Unit 15 by 2016.

(c) One (1) dry bottom pulverized coal-fired boiler identified as Unit 17, with construction started in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 17 has been approved to fire blends of coal and petroleum coke.

(d) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, with construction started in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide

(SO_2) and a continuous opacity monitoring (COM) system. Unit 18 has been approved to fire blends of coal and petroleum coke.

(e) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

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

G.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)] [326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-1-2, 326 IAC 24-2-2, and 326 IAC 24-3-2.

G.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]

(a) The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall operate each source and unit in compliance with this CAIR permit.

(b) The CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit subject to this CAIR permit are Units 14, 15, 17, 18, 16A, and 16B.

G.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall comply with the applicable monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source with the CAIR NO_X emissions limitation under 326 IAC 24-1-4(c), CAIR SO_2 emissions limitation under 326 IAC 24-2-4(c), and CAIR NO_X ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition G.4.1, Nitrogen Oxides Emission Requirements, Condition G.4.2, Sulfur Dioxide Emission Requirements, and Condition G.4.3, Nitrogen Oxides Ozone Season Emission Requirements.

G.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 326 IAC 24-1-11.

(b) A CAIR NO_X unit shall be subject to the requirements under 326 IAC 24-1-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-1-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X allowance shall not be deducted for compliance with the requirements under 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(d) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X annual trading program. No provision of the CAIR NO_X annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in this CAIR permit.

G.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR SO_2 unit shall be subject to the requirements under 326 IAC 24-2-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-2-4(c)(2), and for each control period thereafter.

(c) A CAIR SO_2 allowance shall not be deducted for compliance with the requirements under 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(d) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

(e) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 trading program. No provision of the CAIR SO_2 trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR SO_2 allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in this CAIR permit.

G.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit at the source shall hold, in the source's compliance account, CAIR NO_X ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.

(b) A CAIR NO_X ozone season unit shall be subject to the requirements under 326 IAC 24-3-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-3-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X ozone season allowance shall not be deducted for compliance with the requirements under 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X ozone season allowance was allocated.

(d) CAIR NO_X ozone season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.

(e) A CAIR NO_X ozone season allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X ozone season trading program. No provision of the CAIR NO_X ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X ozone season allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR NO_X ozone season allowance to or from a CAIR NO_X ozone season source's compliance account is incorporated automatically in this CAIR permit.

G.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]

(a) The owners and operators of a CAIR NO_X source and each CAIR NO_X unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation shall do the following:

(1) Surrender the CAIR NO_X allowances required for deduction under 326 IAC 24-1-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-1-4, the Clean Air Act (CAA), and applicable state law.

(b) The owners and operators of a CAIR SO_2 source and each CAIR SO_2 unit that emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation shall do the following:

(1) Surrender the CAIR SO_2 allowances required for deduction under 326 IAC 24-2-8(k)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-2-4, the Clean Air Act (CAA), and applicable state law.

(c) The owners and operators of a CAIR NO_X ozone season source and each CAIR NO_X ozone season unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X ozone season emissions limitation shall do the following:

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

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-3-4, the Clean Air Act (CAA), and applicable state law.

G.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

(a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), and 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), and 326 IAC 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

(d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program or to demonstrate compliance with the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

This period may be extended for cause, at any time before the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

G.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall submit the reports required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the information shall be submitted to:

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

(d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the information shall be submitted to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

G.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]

The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall be liable as follows:

(a) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall meet the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, respectively.

(b) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source.

(c) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit or the CAIR designated representative of a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall also apply to the owners and operators of such unit.

G.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]

No provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

G.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-1-6, 326 IAC 24-2-6, and 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source including all CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program concerning the source or any CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source.

(b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source choose to designate an alternate CAIR designated representative.

OFFICE OF AIR QUALITY

COMPLIANCE AND ENFORCEMENT BRANCH

PART 70 OPERATING PERMIT

CERTIFICATION

Source Name: NIPSCO - Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T073-29983-00008

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: (317) 233-0178
Fax: (317) 233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: NIPSCO - Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T073-29983-00008

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

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

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

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

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

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

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

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

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

Part 70 Quarterly Report

Source Name: NIPSCO - Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T073-29983-00008
Facility: Turbine 16A
Parameter: Operating Hours
Limit: Less than 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	NIPSCO - Schahfer Generating Station
Source Address:	2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.:	T073-29983-00008
Facility:	Turbine 16B
Parameter:	Operating Hours
Limit:	Less than 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

COMPLIANCE AND ENFORCEMENT BRANCH

PART 70 OPERATING PERMIT

QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: NIPSCO - Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T073-29983-00008

Months: _____ to _____ Year: _____

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

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

Pursuant to Section F.1 of this permit, the follow paragraphs and tables of the Decree are incorporated by reference into this permit to the extent they relate to the Schahfer Station.

Decree Paragraphs and Tables
DEFINITIONS: All definitions contained with paragraphs 7 through 59 of the Decree, to the extent such terms are used in any of the paragraphs of the Decree listed in this Attachment A.
¶ NOx EMISSION REDUCTIONS AND CONTROLS: ¶¶ 60, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73 and 74. Tables 1, 2, 3 and 4.
SO_2 EMISSION REDUCTIONS AND CONTROLS: ¶¶ 76, 80, 81, 82, 83, 84, 85, 86, 87, 88 and 89. Tables 5 and 6.
PM EMISSION REDUCTIONS AND CONTROLS: ¶¶ 91, 92, 93 and 94. Table 7.
PM and MERCURY CEMS: ¶¶ 101, 102, 103 and 106.
PERIODIC REPORTING ¶¶ 126 and 127(a).
FORCE MAJEURE: ¶¶ 144, 145, 146, 147, 148, 149, 150, 151 and 152.
NOTICE ¶¶ 178, 179 and 180.
COMPLIANCE DETERMINATION: ¶¶ 196, 200, and 202.

ATTACHMENT B

[PDF COPY OF ENTIRE CONSENT DECREE – FOR INFORMATIONAL PURPOSES – HAS BEEN ATTACHED TO THE PERMIT]

Attachment C
to a Part 70 Operating Permit Renewal

Standards of Performance for Fossil-Fuel-Fired Steam Generators
[40 CFR Part 60, Subpart D] [326 IAC 12]

Source Name:	**NIPSCO – R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911**
Permit Renewal No.:	**T073-29983-00008**
Permit Reviewer:	**Josiah Balogun**

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_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2or 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 (SO_2).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y\,(340) + z\,(520)}{(y + z)}$$

Where:

$PS_{SO}2$= Prorated standard for $S_{O2}$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.43Da(i)(3) of subpart Da of this part or comply with §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.43Da(i)(3) of subpart Da of this part or §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.44 Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_X, expressed as NO_2in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.

(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w\,(260) + x\,(86) + y\,(130) + z\,(300)}{(w + x + y + z)}$$

Where:

PS_{NOX}= Prorated standard for $NO_X$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

x = Percentage of total heat input derived from gaseous fossil fuel;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO_Xdoes not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.44Da(e)(3) of subpart Da of this part.

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator 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_2emissions, NO_Xemissions, 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_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2emissions are not required if the owner or operator monitors SO_2emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2emissions is not required if the owner or operator monitors SO_2emissions by fuel sampling and analysis.

(3) Notwithstanding §60.13(b), installation of a CEMS for NO_Xmay be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of $NO_X$are less than 70 percent of the applicable standards in §60.44, a CEMS for measuring NO_Xemissions is not required. If the initial performance test results show that NO_Xemissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_Xwithin one year after the date of the initial performance tests under §60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO_2or NO_X, a CEMS for measuring either O_2or $CO_2$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_Xcontinuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or $NO_X$the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, $SO_2$and NO_Xspan values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	([1])	500.
Liquid	1,000	500.
Solid	1,500	1,000.
Combinations	1,000y + 1,500z	500 (x + y) + 1,000z.

[1]Not applicable.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel;

y = Fraction of total heat input derived from liquid fossil fuel; and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the $SO_2$and NO_Xspan values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring $O_2$is selected, the measurement of the pollutant concentration and O_2concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$are determined under paragraph (f) of this section.

(2) When a CEMS for measuring $CO_2$is selected, the measurement of the pollutant concentration and CO_2concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, $F_c$and $\%CO_2$are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/MMBtu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for $SO_2$and 46.01 for NO_X.

(3) $\%O_2$, $\%CO_2$= O_2or CO_2volume (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_2generated 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 × 10^{-17}dscm/J (10,140 dscf/MMBtu) and F_c= 0.532 × 10^{-17}scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.637 × 10^{-7}dscm/J (9,820 dscf/MMBtu) and F_c= 0.486 × 10^{-7}scm CO_2/J (1,810 scf CO_2/MMBtu).

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

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

(v) For bark F = 2.589 × 10^{-7}dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10^{-7}scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10^{-7}dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10^{-7}scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.659 × 10^{-7}dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10^{-7}scm CO_2/J (1,920 scf CO_2/MMBtu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or $F_c$factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\,\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\,\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see §60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:

X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

$F_i$or $(F_c)_i$= Applicable F or $F_c$factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity* . Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of §60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of §60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:

(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2as measured by a CEMS exceed the applicable standard in §60.43; or

(ii) For affected facilities electing to comply with §60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2as measured by a CEMS exceed the applicable standard in §60.43. Facilities complying with the 30-day SO_2standard shall use the most current associated SO_2compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part or §§60.45b and 60.47b of subpart Db of this part, as applicable.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring $NO_X$are defined as:

(i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44; or

(ii) For affected facilities electing to comply with §60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_Xas measured by a CEMS exceed the applicable standard in §60.44. Facilities complying with the 30-day NO_Xstandard shall use the most current associated NO_Xcompliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter.* Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in §60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§60.48Da and 60.49Da of subpart Da of this part.

(h) The owner or operator of an affected facility subject to the opacity limits in §60.42 that elects to monitor emissions according to the requirements in §60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

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

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

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

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

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

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

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

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

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

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

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009; 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_Xstandards in §§60.42, 60.43, and 60.44 as follows:

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

$$E = CF_d\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where:

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

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

$\%O_2$= O_2concentration, percent dry basis; and

F_d= Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the SO_2concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be taken simultaneously with, and at the same point as, the SO_2sample. The SO_2emission rate shall be computed for each pair of $SO_2$and O_2samples. The SO_2emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration.

(i) The sampling site and location shall be the same as for the SO_2sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_Xsample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_Xsample.

(iii) The NO_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:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where:

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

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

$\%CO_2$ = CO_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]

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Attachment D
to a Part 70 Operating Permit Renewal

Standards of Performance for Electric Utility Steam Generating Units
[40 CFR Part 60, Subpart Da] [326 IAC 12]

Source Name:	**NIPSCO – R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911**
Permit Renewal No.:	**T073-29983-00008**
Permit Reviewer:	**Josiah Balogun**

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

Source: 72 FR 32722, June 13, 2007, unless otherwise noted.

§ 60.40Da Applicability and designation of affected facility.

(a) Except as specified in paragraph (e) of this section, the affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) An IGCC electric utility steam generating unit (both the stationary combustion turbine and any associated duct burners) is subject to this part and is not subject to subpart GG or KKKK of this part if both of the conditions specified in paragraphs (b)(1) and (2) of this section are met.

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) in the combustion turbine engine and associated heat recovery steam generator; and

(2) The IGCC electric utility steam generating unit commenced construction, modification, or reconstruction after February 28, 2005.

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

(e) Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (3) of this section.

(1) Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are

subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (*i.e.* duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5078, Jan. 28, 2009; 77 FR 9448, Feb. 16, 2012]

§ 60.41Da 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.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

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).

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Biomass means plant materials and animal waste.

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

Boiler operating day for units constructed, reconstructed, or modified before March 1, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *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 the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

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.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Combined heat and power, also known as “cogeneration,” means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

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 heat recovery steam generating unit.

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

Electrostatic precipitator or *ESP* means an add-on air pollution control device used to capture particulate matter (PM) by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emission limitation means any emissions limit or operating limit.

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.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For facilities constructed, reconstructed, or modified before May 4, 2011, the gross electrical or mechanical output from the affected facility 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);

(2) For facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) 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);

(3) For combined heat and power facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) 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);

(4) For a IGCC electric utility generating unit that coproduces chemicals constructed, reconstructed, or modified after May 3, 2011, the gross useful work performed is the gross electrical or mechanical output from the unit minus

electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) that are associated with power production 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). Auxiliary loads that are associated with power production are determined based on the energy in the coproduced chemicals compared to the energy of the syngas combusted in combustion turbine engine and associated duct burners.

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

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

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).

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.

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net energy output means the gross energy output minus the parasitic load associated with power production. Parasitic load includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (*i.e.,* pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility).

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

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, *petroleum* means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Petroleum coke, also known as “petcoke,” means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). *Petroleum coke* is typically derived from oil refinery coker units or other cracking processes.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems. For sulfur dioxide (SO_2) the potential combustion concentration is determined under §60.50Da(c).

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (*e.g.* , a steam generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, *steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.

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).

Wet flue gas desulfurization technology or *wet FGD* means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline 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 FGD technology include, but are not limited to, lime, limestone, and sodium.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009; 77 FR 9448, Feb. 16, 2012; 77 FR 23402, Apr. 19, 2012]

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) 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 is exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(1) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator shall cause to be discharged into the atmosphere from that affected facility at all times except during periods of startup and shutdown, any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction, any gases that contain PM in excess of either:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

(ii) For an affected facility which commenced modification, any gases that contain PM in excess of 13 ng/J (0.015 lb/MMBtu) heat input.

(2) During periods of startup and shutdown, the owner or operator shall meet the work practice standards specified in Table 3 to subpart UUUUU of part 63.

(f) An owner or operator of an affected facility that meets the conditions in either paragraphs (f)(1) or (2) of this section is exempt from the PM emissions limits in this section.

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

(2) The affected facility is operated under a PM commercial demonstration permit issued by the Administrator according to the provisions of §60.47Da.

[77 FR 9450, Feb. 16, 2012]

§ 60.43Da Standards for sulfur dioxide (SO2).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain SO_2in excess of:

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain SO_2in excess of:

(1) 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO_2in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The SO_2standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO_2commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of $SO_2$to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = 10$$

(2) If emissions of $SO_2$to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100}$$

Where:

E_s= Prorated SO_2emission limit (ng/J heat input);

$\%P_s$= Percentage of potential SO_2emission allowed;

x = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and

y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2in excess of the applicable emissions limit specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

(j) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emissions limit specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (j) and (m) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2in excess of the applicable emissions limit specified in paragraphs (l)(1) and (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO_2in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 140 ng/J (1.2 lb/MWh) net energy output; or

(iii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emissions limit specified in paragraphs (m)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

[72 FR 32722, June 13, 2007, as amended at 77 FR 9450, Feb. 16, 2012]

§ 60.44Da Standards for nitrogen oxides (NO_X).

(a) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before July 10, 1997 any gases that contain NO_X(expressed as NO_2) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_Xin excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30-boiler operating day rolling average basis.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50

All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	([1])	([1])
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace[2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit[2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1]Exempt from NOX standards and NOX monitoring requirements.

[2]Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (E_n) is determined by proration using the following formula:

$$En = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

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Where:

En = Applicable NO_X emissions limit when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(b)–(c) [Reserved]

(d) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after July 9, 1997, but before March 1, 2005, 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 applicable emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_Xin excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_Xin excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraphs (f) and (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, 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 applicable emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_Xin excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_Xin excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO_Xin excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30-boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day compliance period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Except as provided in paragraphs (h) of this section and §60.45Da, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, 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 applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_Xin excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_Xin excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_Xin excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO_Xemissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

[77 FR 9451, Feb. 16, 2012]

§ 60.45Da Alternative standards for combined nitrogen oxides (NOX) and carbon monoxide (CO).

(a) The owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011 as alternate to meeting the applicable NO_Xemissions limits specified in §60.44Da may elect to meet the applicable standards for combined $NO_X$and CO specified in paragraph (b) of this section.

(b) 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 commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_Xplus CO in excess of either:

(i) 140 ng/J (1.1 lb/MWh) gross energy output; or

(ii) 150 ng/J (1.2 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_Xplus CO in excess of either:

(i) 160 ng/J (1.3 lb/MWh) gross energy output; or

(ii) 170 ng/J (1.4 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_Xplus CO in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

[77 FR 9453, Feb. 16, 2012]

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO_2emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of an affected facility that uses fluidized bed combustion (atmospheric or pressurized) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO_2emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_Xemission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SCR I)	SO2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO2	400–3,000
Fluidized bed combustion (pressurized)	SO2	400–1,200

Coal liquification	NOX	750–10,000
Total allowable for all technologies		15,000

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under §60.42Da but must, as a minimum, reduce PM emissions to less than 6.4 ng/J (0.015 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2standards or emission reduction requirements under §60.43Da but must, as a minimum, reduce SO_2emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions control system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO_Xstandards or emission reduction requirements under §60.44Da but must, as a minimum, reduce NO_Xemissions to less than 130 ng/J (1.0 lb/MWh) or the combined NO_Xplus CO emissions to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category listed in the following table.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO_2	1,000
Multi-pollutant Emission Control	NO_X	1,000
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO_2	1,000
Pressurized Fluidized Bed Combustion	NO_X	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO_X	1,000

[72 FR 32722, June 13, 2007, as amended at 77 FR 9450, Feb. 16, 2012]

§ 60.48Da Compliance provisions.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under §60.42Da, SO_2emissions limit under §60.43Da, and NO_Xemissions limit under §60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO_2emissions limit under §60.43Da, NO_Xemissions limit under §60.44Da, and NO_Xplus CO emissions limit under §60.45Da apply at all times. The applicable PM emissions limit and opacity standard under §60.42Da apply at all times except during periods of startup and shutdown.

(b) After the initial performance test required under §60.8, compliance with the applicable SO_2emissions limit and percentage reduction requirements under §60.43Da, NO_Xemissions limit under §60.44Da, and NO_Xplus CO

emissions limit under §60.45Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for both SO_2, NO_Xor NO_Xplus CO as applicable, and a new percent reduction for $SO_2$are calculated to demonstrate compliance with the standards.

(c) For the initial performance test required under §60.8, compliance with the applicable SO_2emissions limits and percentage reduction requirements under §60.43Da, the NO_Xemissions limits under §60.44Da, and the NO_Xplus CO emissions limits under §60.45Da is based on the average emission rates for SO_2, NO_X, CO, and percent reduction for $SO_2$for the first 30 successive boiler operating days. The initial performance test is the only test in 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 boiler operating day of the 30 successive boiler operating days is completed 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 startup of the facility.

(d) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average $SO_2$and NO_Xemissions limits is determined by calculating the arithmetic average of all hourly emission rates for $SO_2$and $NO_X$for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average $SO_2$and NO_Xemissions limits is determined by dividing the sum of the $SO_2$and NO_Xemissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(e) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable SO_2percentage reduction requirements is determined based on the average inlet and outlet SO_2emission rates for the 30 successive boiler operating days. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable SO_2percentage reduction requirements is determined based on the “as fired” total potential emissions and the total outlet SO_2emissions for the 30 successive boiler operating days.

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable daily average PM emissions limits is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable daily average PM emissions limits is determined by dividing the sum of the PM emissions for the 30 successive boiler operating days by the sum of the gross useful output or net energy output, as applicable, for the 30 successive boiler operating days.

(g) For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NO_Xplus CO emissions limit is determined by dividing the sum of the NO_Xplus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19 of appendix A of this part.

(i) *Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), (f), or (g).* The owner or operator shall calculate NO_Xemissions as 1.194×10^{-7}lb/scf-ppm times the average hourly NO_Xoutput concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, NO_Xemissions may be calculated by multiplying the hourly NO_Xemission rate in lb/MMBtu (measured by the CEMS required under §60.49Da(c) and (d)), by the hourly heat input rate

(measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1)* . To determine compliance with the emissions limits for NO_Xrequired by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the CEMS specified under §60.49Da for measuring $NO_X$and oxygen (O_2) (or carbon dioxide (CO_2)) and meet the requirements of §60.49Da. Alternatively, data from a NO_Xemission rate (*i.e.* , NO_X-diluent) CEMS certified according to the provisions of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used, with the following caveats. Data used to meet the requirements of §60.51Da shall not include substitute data values derived from 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. The sampling site shall be located at the outlet from the steam generating unit. The NO_Xemission rate at the outlet from the steam generating unit shall constitute the NO_Xemission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1)* . To determine compliance with the emission limitation for NO_Xrequired by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO_Xshall be computed using Equation 2 in this section:

$$E = \frac{(Csg \times Qsg) - (Cte \times Qte)}{(Osg \times h)} \quad (Eq. 2)$$

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Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

C_{te}= Average hourly concentration of NO_Xin the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h);

Q_{te}= Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/h (dscf/h);

O_{sg}= Average hourly gross energy output from steam generating unit, J/h (MW); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_X concentrations (C_{sg} and C_{te}). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Q_{sg} and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$E = \frac{(Csg \times Qsg)}{Occ} \quad (\mathbf{Eq.\ 3})$$

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Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

(ii) The CEMS specified under §60.49Da for measuring NO_X and O_2 (or CO_2) shall be used to determine the average hourly NO_X concentrations (C_{sg}). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q_{sg}) of the exhaust gas. If the option to use the flow monitoring system in §60.49Da(m) is selected, the flow rate data used to meet the requirements of §60.51Da shall not include substitute data values derived from 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. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O_{cc}), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/h) of NO_X emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \quad (Eq. 4)$$

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Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

ER_{sg} = Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc} = Average hourly heat input rate of entire combined cycle unit, J/h (MMBtu/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) 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 steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. 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 regulated under this part.

(l) [Reserved]

(m) Compliance provisions for sources subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), (j)(3)(i), (l)(1)(i), (l)(1)(ii), or (l)(2). The owner or operator shall calculate SO_2 emissions as 1.660×10^{-7} lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, SO_2 emissions may be calculated by multiplying the hourly SO_2 emission rate (in lb/MMBtu), measured by the CEMS required under §60.49Da, by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(n) Compliance provisions for sources subject to §60.42Da(c)(1) or (e)(1)(i). The owner or operator shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of §60.49Da(t)), by the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(o) *Compliance provisions for sources subject to §60.42Da(c)(2) or (d)* . Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by the applicable date specified in §60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in §60.8 using the test methods and procedures in §60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30 calendar days after the next boiler

operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

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

(ii) You must comply with the quality assurance requirements in paragraphs (o)(2)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a 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.

(B) You 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.

(C) You 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.

(D) 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.

(E) You 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.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your opacity baseline level is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level. In cases when a wet scrubber is used in combination with another PM control device that serves as the primary PM control device, the wet scrubber must be maintained and operated.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected facility remains at a level greater than the opacity baseline level after 7 boiler operating days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a waiver is granted by the permitting authority.

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS “Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and 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 Continuous Emission Monitoring.

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the model parameter was first determined to exceed its baseline level unless a waiver is granted by the permitting authority.

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

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

(B) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must 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.)

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

(D) In the initial adjustment of the bag leak detection system, you 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.

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you 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 (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

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

(ii) You must develop and submit to the permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You 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 (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

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

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

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

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

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the permitting authority may allow owners and operators 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.

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you 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:

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

(B) Sealing off defective bags or filter media;

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

(D) Sealing off a defective fabric filter compartment;

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

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

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

(B) 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 system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) If after any period composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the alarm rate was first determined to exceed 5 percent limit unless a waiver is granted by the permitting authority.

(5) An owner or operator of a modified affected facility electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, evaluate, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each CEMS shall be installed, evaluated, operated, and maintained according to the requirements in §60.49Da(v).

(3) 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 the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

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

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh 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.

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) 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, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-boiler operating day rolling average.

(q) *Compliance provisions for sources subject to §60.42Da(b)* . An owner or operator of an affected facility subject to the opacity standard in §60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in §60.49Da(a), as applicable to the affected facility.

(r) Compliance provisions for sources subject to §60.45Da. To determine compliance with the NO_Xplus CO emissions limit, the owner or operator shall use the procedures specified in paragraphs (r)(1) through (3) of this section.

(1) Calculate NO_Xemissions as 1.194×10^{-7}lb/scf-ppm times the average hourly NO_Xoutput concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(2) Calculate CO emissions by multiplying the average hourly CO output concentration (measured according to the provisions of §60.49Da(u), by the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(3) Calculate NO_Xplus CO emissions by summing the NO_Xemissions results from paragraph (r)(1) of this section plus the CO emissions results from paragraph (r)(2) of this section.

(s) Affirmative defense for exceedance of emissions limit during malfunction. In response to an action to enforce the standards set forth in paragraph §§60.42Da, 60.43Da, 60.44Da, and 60.45Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense as specified in paragraphs (s)(1) and (2) of this section. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (s)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emissions limits were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in §63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (s)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009; 76 FR 3522, Jan. 20, 2011; 77 FR 9454, Feb. 16, 2012]

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in §60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (3) of this section.

(1) Except as provided for in paragraphs (a)(2) and (4) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in §60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs §60.48Da(o)(4)(i) through (v);

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

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or CO emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section; or

(iv) The affected facility uses an ESP 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.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

(i) The owner or operator shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11. If during the initial 60 minutes of the observation all the 6-minute averages are less than 10 percent and all the individual 15-second observations are less than or equal to 20 percent, then the observation period may be reduced from 3 hours to 60 minutes.

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) 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)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(C) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If 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 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 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

(C) 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.

(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 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)(3)(iii)(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 (a)(3)(i) of this section within 45 calendar days according to the requirements in §60.50Da(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.

(4) An owner or operator of an affected facility that is subject to an opacity standard under §60.42a(b) is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2emissions 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. 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 §60.51Da(d).

(ii) The owner or operator of the affected facility 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.

(iv) 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)(3)(iii) 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) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less are the only fuels combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2emissions are only monitored as discharged to the atmosphere.

(3) An “as fired” fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential SO_2emissions in place of a continuous SO_2emission monitor at the inlet to the SO_2control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a SO_2CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A CO_2or O_2continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an SO_2emission limit in lb/MMBtu under §60.43Da:

(A) When relative accuracy testing is conducted, SO_2concentration data and CO_2(or O_2) data are collected simultaneously; and

(B) 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

(iii) The reporting requirements of §60.51Da are met. The $SO_2$and, if required, CO_2(or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_Xemissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NO_Xemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da 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.

(d) The owner or operator of an affected facility not complying with an output based limit shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2or carbon dioxide (CO_2) content of the flue gases at each location where SO_2or NO_Xemissions are monitored. For affected facilities subject to a lb/MMBtu SO_2emission limit under §60.43Da, if the owner or operator has installed and certified a CO_2or O_2monitoring system according to §75.20(c) of this chapter and appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO_2concentration monitoring system described in paragraph (b) of this section, to determine the SO_2emission rate in lb/MMBtu. SO_2data used to meet the requirements of §60.51Da shall not include substitute data values derived from 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.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data

with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 of appendix A of this part shall be used to determine the SO_2concentration at the same location as the SO_2monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration at the same location as the NO_Xmonitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2or CO_2concentration at the same location as the O_2or CO_2monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine O_2, SO_2, and NO_Xconcentrations, respectively.

(2) SO_2or NO_X(NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a COMS is between 60 and 80 percent. Span values for a CEMS measuring NO_Xshall be determined using one of the following procedures:

(i) Except as provided under paragraph (i)(3)(ii) of this section, NO_Xspan values shall be determined as follows:

Fossil fuel	**Span values for NO_X (ppm)**
Gas	500.
Liquid	500.
Solid	1,000.
Combination	500 (x + y) + 1,000z.

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 (i)(3)(i) of this section, the owner or operator of an affected facility may elect to use the NO_Xspan values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

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

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO_2control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO_2span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under §60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) 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 1 hour.

(3) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used if the sampling time is 1 hour.

(4) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross energy output for sources demonstrating compliance with an output-based standard.

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For an affected facility generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of “gross energy output” specified in §60.41Da that is applicable to the affected facility.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of §60.51Da shall not include substitute data values derived from 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.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NO_Xstandards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure NO_Xemissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p)–(r) [Reserved]

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.* , on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in §60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) The owner or operator of an affected facility using a CEMS measuring CO emissions to meet requirements of this subpart shall meet the requirements specified in paragraphs (u)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(1)(i) through (iv) of this section.

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

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

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

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

(2) You must calculate the 1-hour average CO emissions levels for each 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 useful energy output from the affected facility. 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.

(3) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, 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 1.4 lb/MWh or less.

(4) You must record the CO measurements and calculations performed according to paragraph (u)(3) 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 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(4) of this section.

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each PM correlation testing run 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 CEMS 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.

(3) 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.

(4) 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.

(w) The owner or operator using a SO_2, NO_X, CO_2, and O_2CEMS to meet the requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (w)(1) through (w)(5) of this section.

(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, each SO_2, NO_X, CO_2, and O_2CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under §60.51Da.

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS 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 of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$and NO_Xspan values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_Xspan values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO_2, CO_2, and O_2CEMS and for NO_XCEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2(regardless of the SO_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, 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 paragraphs (w)(2) through (w)(4) of this section.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5081, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9456, Feb. 16, 2012; 77 FR 23402, Apr. 19, 2012]

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A 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 for $SO_2$and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) In conducting the performance tests to determine compliance with the PM emissions limits in §60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in §60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14 °C (320 ± 25 °F).

(B) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2concentration. The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2standards in §60.43Da as follows:

(1) The percent of potential SO_2emissions (%Ps) to the atmosphere shall be computed using the following equation:

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

Where:

%Ps = Percent of potential SO_2emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by SO_2control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO_2reduction ($\%R_g$) of any SO_2control system. Alternatively, a combination of an “as fired” fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if

the percent reduction is calculated using the average emission rate from the SO_2control device and the average SO_2input rate from the “as fired” fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of $SO_2$and CO_2or O_2.

(d) The owner or operator shall determine compliance with the NO_Xstandard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of NO_X.

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of $NO_X$and CO_2or O_2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) 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 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 in 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 is saturated or laden with water droplets.

(2) The $F_c$factor (CO_2) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO_2shall be determined in the same manner as the O_2concentration.

(f) Electric utility combined cycle gas turbines that are not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas are performance tested for PM, SO_2, and NO_Xusing the procedures of Method 19 of appendix A–7 of this part. The $SO_2$and NO_Xemission rates calculations from the gas turbine used in Method 19 of appendix A–7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5083, Jan. 28, 2009; 77 FR 9458, Feb. 16, 2012]

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and NO_Xplus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) For $SO_2$and $NO_X$the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average $SO_2$and NO_Xemission rates (ng/J, lb/MMBtu, or lb/MWh) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) For owners or operators of affected facilities complying with the percent reduction requirement, percent reduction of the potential combustion concentration of $SO_2$for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

(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 CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) and conducting performance tests using Method 9 of appendix A–4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.

(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 (d)(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) [Reserved]

(e) If fuel pretreatment credit toward the SO_2emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; 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 previous quarter.

(f) For any periods for which opacity, SO_2 or NO_X emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) [Reserved]

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) 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 (b) and (i) 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.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5083, Jan. 28, 2009; 77 FR 9458, Feb. 16, 2012]

§ 60.52Da Recordkeeping requirements.

(a) [Reserved]

(b) The owner or operator of an affected facility subject to the opacity limits in §60.42Da(b) that elects to monitor emissions according to the requirements in §60.49Da(a)(3) shall maintain records according to the requirements specified in paragraphs (b)(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 (b)(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 (b)(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.

[74 FR 5083, Jan. 28, 2009, as amended at 77 FR 9459, Feb. 16, 2012]

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Attachment E
to a Part 70 Operating Permit Renewal

Standards of Performance for Coal Preparation and Processing Plants
[40 CFR Part 60, Subpart Y] [326 IAC 12]

Source Name:	**NIPSCO – R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911**
Permit Renewal No.:	**T073-29983-00008**
Permit Reviewer:	**Josiah Balogun**

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_2emissions 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_2in 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_2in excess of 520 ng/J (1.20 lb/MMBtu) heat input or contain SO_2in 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_2limit 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_2limits 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_Xlimit 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_2concentration. A minimum of three valid test runs are needed to comprise an SO_2performance test.

(7) Method 7 or 7E of appendix A–4 of this part shall be used to determine the NO_Xconcentration. A minimum of three valid test runs are needed to comprise an NO_Xperformance 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_Xperformance 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 F – Applicable Portions of the Standards of Performance for Stationary Gas Turbines Requirements [40 CFR Part 60, Subpart GG] [326 IAC 12]

Source Description and Location

Source Name:	NIPSCO – R.M. Schahfer Generating Station
Source Location:	2723 East 1500 North, Wheatfield, IN 46392
County:	Jasper
SIC Code:	4911
Permit Renewal No.:	T073-29983-00008
Permit Reviewer:	Josiah Balogun

Applicable Portions of the NSPS

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

§ 60.331 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.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *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.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; 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.

(u) *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. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 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.

(v) *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 heat recovery steam generating unit.

(w) *Lean premix stationary combustion turbine* means any 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. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *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. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *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 unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_Xemission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_Xemission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_Xemission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_Xemission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_Xallowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_Xemission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO_Xpercent by volume)
$N \leq .015$	0
$0.015 < N \leq 0.1$	0.04 (N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in theFederal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_Xemissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979,Federal Register(44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_Xemissions shall 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.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_Xemissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of $NO_X$and O_2monitors. As an alternative, a CO_2monitor may be used to adjust the measured NO_Xconcentrations to 15 percent $O_2$by either converting the CO_2hourly averages to equivalent O_2concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the $NO_X$and diluent monitors may be performed individually or on a combined basis, *i.e.* , the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2basis for oxygen; or

(ii) On a ppm at 15 percent O_2basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2basis (for a CO_2monitor that uses the procedures in Method 20 to correct the NO_Xdata to 15 percent O_2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each 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 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 to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both $NO_X$and diluent, the data acquisition and handling system must calculate and record the hourly NO_Xemissions in the units of the applicable NO_Xemission standard under §60.332(a), *i.e.* , percent $NO_X$by volume, dry basis, corrected to 15 percent $O_2$and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O_2concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_XCEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_Xemissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_Xemission limit under §60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_Xemissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_Xemissions, may, but is not required to, elect to use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_Xemissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_Xformation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_Xmode.

(3) For any turbine that uses SCR to reduce NO_Xemissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_Xemission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator 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. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_Xemission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NO_Xemission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.* , if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. 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.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *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). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) 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 (i)(3)(i) and (i)(3)(ii) 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 §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) 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 (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), 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 between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) 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:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.* , the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) 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 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the 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 §60.332, 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 shall also be considered an excess emission.

(B) A period of monitor downtime shall be 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.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) 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 that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using $NO_X$and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_Xconcentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_Xconcentration" is the arithmetic average of the average NO_Xconcentration measured by the CEMS for a given hour (corrected to 15 percent $O_2$and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_Xconcentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_Xconcentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_Xemission controls:

(A) An excess emission shall be 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.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) 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 gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall 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 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) 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 shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006]

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine $NO_X$and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall 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.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for $NO_X$and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_Xconcentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 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 3 points shall be located along the measurement line that exhibited the highest average normalized NO_Xconcentration during the stratification test; or

(B) If each of the individual traverse point NO_Xconcentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O_2shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units

used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}$ e19 $(Ho-0.00633)(288°K/T_a)^{1.53}$

Where:

NO_X= emission concentration of NO_Xat 15 percent $O_2$and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo}= mean observed NO_Xconcentration, ppm by volume, dry basis, at 15 percent O_2,

P_r= reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o= observed combustor inlet absolute pressure at test, mm Hg,

H_o= observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a= ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_Xemissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_Xemission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control $NO_X$with no additional post-combustion NO_Xcontrol and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NO_Xemission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_XCEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall 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 §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006]

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Attachment G
to a Part 70 Operating Permit Renewal

40 CFR 63, Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:

Source Name:	**NIPSCO – R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911**
Permit Renewal No.:	**T073-29983-00008**
Permit Reviewer:	**Josiah Balogun**

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[75 FR 51589, Aug. 20, 2010]

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

[75 FR 51589, Aug. 20, 2010]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

Where:

C_i= concentration of CO or formaldehyde at the control device inlet,

C_o= concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq. 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

%CO_2= Measured CO_2concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number,

viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are

deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity

or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101–549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under §63.6640(f). All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant,

including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]

Table 1ato Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .

1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

[76 FR 12867, Mar. 9, 2011]

Table 2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .

1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2bto Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to	a. maintain your catalyst so that the pressure drop across the catalyst does not change by

reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst	Comply with any operating limitations approved by the Administrator.

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]

Table 2cto Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

	annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]	

	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency,	Limit concentration of CO	

non-black start 4SLB stationary RICE 100≤HP≤500	in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 51593, Aug. 20, 2010]

Table 2dto Subpart ZZZZ of Part 63— Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission

		limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace	

	as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours	

	of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 93 percent or more.	
9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or	
	b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs	

	every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[75 FR 51595, Aug. 20, 2010]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE	Conduct subsequent performance tests semiannually.[1]

	exhaust	
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[75 FR 51596, Aug. 20, 2010]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[a](incorporated by reference, see §63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[ab](incorporated by reference, see §63.14)

		control device		or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. Reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005)	(a) Measurements to determine O_2concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the	(1) Method 3 or 3A or	(a) Measurements to

		O_2concentration of the stationary RICE exhaust at the sampling port location; and	3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)	determine O_2concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03	(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b]You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c]You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[75 FR 51597, Aug. 20, 2010]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if. . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to

HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI	a. Limit the	i. You have installed a CEMS to

RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	concentration of CO, and using a CEMS	continuously monitor CO and either O_2or CO_2at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to

		the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of formaldehyde and not using NSCR	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission limitation; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the

		Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

[76 FR 12867, Mar. 9, 2011]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating

		limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and

		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year		
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and

		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate,

calendar year	exhaust, and not using an oxidation catalyst or NSCR	percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[76 FR 12870, Mar. 9, 2011]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each ...	You must submit a ...	The report must contain ...	You must submit the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the	

located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP		CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4) i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the requirements in §63.6650(b).	
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and i. Annually, according to the requirements in §63.6650.	
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and i. See item 2.a.i.	
		c. Any problems or errors suspected with the meters.	

		i. See item 2.a.i.	

[75 FR 51603, Aug. 20, 2010]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	

§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	

§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only	

		applies as specified in §63.6645.	
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.

§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)–(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources	Yes	Except that §63.10(c)(2)–(4)

	using CEMS		and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i)(C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010]

Attachment H: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR 60, Subpart IIII]

Source Description and Location

Source Name:	NIPSCO – R.M. Schahfer Generating Station
Source Location:	2723 East 1500 North, Wheatfield, IN 46392
County:	Jasper
SIC Code:	4911
Permit Renewal No.:	T073-29983-00008
Permit Reviewer:	Josiah Balogun

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the useful life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Reduce nitrogen oxides (NO_X) emissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (g/KW-hr) (1.2 grams per HP-hour (g/HP-hr)).

(2) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_Xemissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and §60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and $NO_X$and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit $NO_X$and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i= concentration of NO_Xor PM at the control device inlet,

C_o= concentration of NO_Xor PM at the control device outlet, and

R = percent reduction of NO_Xor PM emissions.

(2) You must normalize the NO_Xor PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \% O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

$\%O_2$= Measured O_2concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent $O_2$and CO_2concentration is measured in lieu of O_2concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{H}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and PM gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

$\%CO_2$= Measured CO_2concentration, dry basis, percent.

(e) To determine compliance with the NO_Xmass per unit output emission limitation, convert the concentration of NO_Xin the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d= Measured NO_Xconcentration in ppm.

1.912×10^{-3}= Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj}= Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §60.4205. Non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder, must meet the applicable emission standards in §60.4204(c).

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI engines located in areas of Alaska not accessible by the Federal Aid Highway System should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) The Governor of Alaska may submit for EPA approval, by no later than January 11, 2008, an alternative plan for implementing the requirements of 40 CFR part 60, subpart IIII, for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. This alternative plan must be based on the requirements of section 111 of the Clean Air Act including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR part 60, subpart IIII. If EPA approves by rulemaking process an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel engines used in new stationary internal combustion engines subject to this paragraph.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

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

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X+ NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.
[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.
[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.
[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_Xemissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for

For each	Complying with the requirement to	You must	Using	According to the following requirements
				NO_Xconcentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_Xconcentration.
		iv. Measure NO_Xat the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_Xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_Xin the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurement for NO_Xconcentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_Xconcentration.
		iv. Measure NO_Xat the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(d) NO_Xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each	Complying with the requirement to	You must	Using	According to the following requirements
			(incorporated by reference, see §60.17)	
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		location; and		
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Indiana Department of Environmental Management
Office of Air Quality

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Addendum to the Technical Support Document (ATSD) for a Part 70 Operating Permit (TITLE V)

Source Background and Description

Source Name:	**NIPSCO – R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911**
Permit Renewal No.:	**T073-29983-00008**
Permit Reviewer:	**Josiah Balogun**

On October 16, 2012, the Office of Air Quality (OAQ) had a notice published in the Rensselaer Republican in Rensselaer, Indiana, stating that NIPSCO – Schahfer Generating Station had applied for a Part 70 Operating Permit (TITLE V) to continue to operate an electric Utility generating station. The notice also stated that OAQ proposed to issue a Title V permit for this operation and provided information on how the public could review the proposed Title V and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this Title V permit should be issued as proposed.

On November 11, 2012, John Ross of NiSource Corporate Services submitted comments on the proposed Title V Operating Permit. The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice. Changes that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

The summary of the comments and IDEM, OAQ responses, including changes to the permit No. T127-29983-00008 (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comment 1: **Table of Contents** - B.17 through B.20 in the table of contents do not reflect the actual sections in the body of the permit. The corrected order for these sections in the body of the permit is provided below:

B.17 Source Modification Requirement [326 IAC 2-7-10.5]
B.18 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]
B.19 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12(b)(2)]
B.20 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

Response 1: The table of content in the permit has been revised to update the above information from the source.

Comment 2: **Section C.21 (e)** for EUSGUs the rule requires a notice with the initial record to be submitted before beginning actual construction for projects that meet the reasonable possibility criteria. Therefore in Section (e) of C.21, please insert text "…the Permittee shall submit the initial record per (c)(1) in Section C – General Record Keeping Requirements and a report to the department within.." as found below:

(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 (EUSGU), **the Permittee shall submit the initial record per (c)(1) in Section C – General Record Keeping Requirements and** a report to the department within sixty (60) days after the end of each year during which records must be generated under subdivision (3)[326 IAC 2-2-8(b)(3)] setting out the unit's annual emissions during the calendar year that preceded submission of the report.

Response 2: The statement inserted by NIPSCO - Schahfer Generationg Station in to subcondition C.21(e) is redundant, therefore, the condition shall not be revised.

Comment 3: **Section C.21 (g)** Please insert text as found below to clarify requirement to submit a report per C.21.

(g) **If required to submit a report per subsection (f) above, ~~T~~t**he report for project at an existing emissions unit shall be submitted no later than 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 projection.

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

Response 3: The statement inserted by NIPSCO - Schahfer Generationg Station in to subcondition C.21(e) is redundant, therefore, the condition shall not be revised.

Comment 4: Section E.3.2 change reference for regulatory citation from Subpart "Db" to "Da"

Response 4: The citation has been corrected in the permit accordingly.

E.3.2 Standards of Performance for Electric Utility Steam Generating Units [40 CFR Part 60, Subpart **Da**~~Db~~] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart **Da**~~Db~~, the Permittee shall comply with the provisions of the Standards of Performance for Electric Utility Steam Generating Units, which are incorporated by

reference as 326 IAC 12, for the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18 as specified as follows:

.....

Comments 5: List of Insignificant Activities in the TSD

There is a list of 41 insignificant activities associated with the source in the TSD. However, there are only eight such activities in section A.3 of the permit. For example, the TSD lists "(39) Farm operations" as an insignificant activity. There are no farm operations at the source. Please change the TSD list to reflect the eight insignificant activities found in section A.3.

Response 5: The lists of insignificant activies in the permit are the ones that are Specifically Regulalted by rules in the permit. The other in the Technical Support Document are not regulated but they are existing at the source. The farm operations have been deleted from the list of insignificant activities. IDEM acknowledges the above facts by the ATSD. No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice.

Insignificant Activities

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

.....

~~(39) Farm operations.~~

(~~40~~**39**) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

.....

(~~41~~**40**) Two (2) diesel fired-engines for emergency quench pumps, each rated at 144 horsepower, to be permitted in 2012.[Under 40 CFR 60, Subpart IIII, emergency quench pumps are considered new affected sources]

Comments 6: Technical Support Document – Emissions Calculations

The tables with emissions estimates for potential to emit (PTE) and limited PTE after issuance in the Technical Support Document (TSD) appear to have some inaccurate information. The PM, PM10 and PM2.5 number(s) for Unit 15, 17 and 18 are overstated for the PTE after issuance of renewal permit. As an example for Unit 15, this unit has an NSPS limitation for PM of 0.1 lb/mmBtu that is not reflected in the calculation. On the other hand, the SO2 emission estimates for all units appear to be understated; this is especially true for Units 14 and 15 PTE after issuance of renewal permit. The amount of SO2 emissions listed in the PTE after issuance of renewal permit table for Units 14 and 15 are actually lower than the normal average actual emissions for those units. For SO2, there appears to be an error in the emission factor for calculation of SO2 emissions. The Unit 17/18 SO2 emissions from the limited PTE after issuance do not appear to reflect the NIPSCO Consent Decree per cent removal requirements. Also, the NOx emission estimates for PTE after issuance of renewal permit table do not appear to consider emission rate limitations from the NIPSCO consent decree. In general, corrections to the emissions estimates spreadsheets would impact unlimited and limited PTE calculations and a significant amount of work would be needed to consistently improve the accuracy of the data in the tables. NIPSCO is available to help IDEM in the process of improving the accuracy of the emissions estimates in the tables in the TSD.

Response 6: No changes shall be made to the Technical Support Document (TSD) because the OAQ prefers that the TSD reflects the document that was public noticed. The Limited calculations has been revised. All applicable limits have been applied to the limited PTE after issuance in the Technical Support Document (TSD). The new limited PTE table also includes the NIPSCO Consent Decree limits. The Potential to Emit table that appeared on pages 12 and 13 of 26 of the TSD in the public notice document contained errors and has been corrected. IDEM has revised this Potential to Emit table and the revisions are documented below in this Addendum to the Technical Support Document (ATSD).

Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM	PM10*	PM2.5	SO_2	VOC	CO	NOx	GHG as CO2e	Total HAPs
Cyclone Boiler Unit 14	~~88.6~~ **2036.7**	~~484~~ **1493.9**	~~484~~ **1493.9**	~~5313~~ **16375.8**	~~97.4~~ **121.5**	~~443~~ **522.5**	~~29222~~ **2444**	4581097	1207
Dry bottom pulverized boiler Unit 15	~~54282~~ **2234**	~~12485~~ **14432**	~~12485~~ **14432**	~~6031~~ **26806**	~~60~~ **75**	~~1639~~ **2046**	~~11057~~ **4021**	4844241	1362
Dry bottom pulverized boiler Unit 17	524	~~9711~~ **16006**	~~9711~~ **16006**	~~10790~~ **2852**	47	4691	~~9383~~ **3475**	3759709	1059.6
Dry bottom pulverized boiler Unit 18	524	~~9711~~ **16006**	~~9711~~ **16006**	~~10790~~ **2852**	47	4691	~~9383~~ **3475**	3759709	1059.6
Combustion Turbine Unit 16A	42	42	42	22	13.3	521	2032	741533	6.2
Combustion Turbine Unit 16B	42	42	42	22	13.3	521	2032	741533	6.2
Coal Storage and Handling for Unit 14 & 15 Boilers	33.3	12	12	0	0	0	0	0	0
Fuel Storage and Handling for Unit 17 & 18 Boilers	> 25	> 15	> 10	0	0	0	0	0	0
Material Handling for Unit 17 and 18	131	131	131	0	0	0	0	0	0
Dry ash handling and disposal	209	209	209	0	0	0	0	0	0
Material Handling for Unit 14 and 15									

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM	PM10*	PM2.5	SO_2	VOC	CO	NOx	GHG as CO2e	Total HAPs
Limestone Drop Point - Fugitive	2.32	1.1	0.17	0	0	0	0	0	0
Gypsum Drop Point - Fugitive	2.83	1.34	0.20	0	0	0	0	0	0
Storage Pile Maintenance	4.35	2.18	0.87	0	0	0	0	0	0
Limestone Vehicle Traffic	5.35	1.07	0.26	0	0	0	0	0	0
Gypsum Vehicle Traffic	6.6	1.68	0.168	0	0	0	0	0	0
Emergency generator	0.05	0.03	0.03	0.29	0.05	0.4	1.73	83.8	0.0008
Total PTE of Entire Source	**~~> 55923~~ > 5822.50**	**~~> 32849~~ > 48,396**	**~~> 32839~~ > 48,386**	**~~32967~~ 48,930**	**~~278~~ 317**	**~~12506~~ 12,993**	**~~63,111~~ 17,480.7**	**18,427,822**	**> 10 > 25**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100000	10/25
PSD Major Source Thresholds	100	100	100	100	100	100	100	100000	NA
negl. = negligible *Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), not particulate matter (PM), is considered as a "regulated air pollutant".									

Notes:

The numbers reported in the Potential to Emit Table above are based on certain assumptions and therefore, does not reflect the maximum allowable emissions from the plant. Accordingly, the information included in the Table, does not constitute enforceable conditions, and is not to be relied on in evaluating actual or allowable emissions from the plant.

Other Changes

Upon further review IDEM, OAQ has made the following changes to the Title V permit T073-29983-00008. (deleted language appears as ~~strikout~~ and the new language **bolded**):

Change 1: The word "effective date" has been removed from the box in the front page of the permit.

Operation Permit No.: T073-29983-00008	
Issued by: Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: ~~Effective date:~~ Expiration Date:

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Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Operating Permit Renewal

Source Background and Description

Source Name:	NIPSCO – R.M. Schahfer Generating Station
Source Location:	2723 East 1500 North, Wheatfield, IN 46392
County:	Jasper
SIC Code:	4911
Permit Renewal No.:	T073-29983-00008
Permit Reviewer:	Josiah Balogun

The Office of Air Quality (OAQ) has reviewed the operating permit renewal application from NIPSCO – R.M. Schahfer Generating Station relating to the operation of an electric utility generating station. On December 8, 2010, NIPSCO – R.M. Schahfer Generating Station submitted an application to the OAQ requesting to renew its operating permit. NIPSCO – R.M. Schahfer Generating Station was issued its first Part 70 Operating Permit T073-6792-00008 on September 7, 2006.

Source Definition

This stationary source consists of an electric utility generating station with an on-site contractor that processes and moisture conditions fly ash:

(1) The electric utility generating station, NIPSCO, Schahfer Station, is the primary operation and is located at 2723 East, 1500 North, Wheatfield, Indiana; and

(2) The fly ash processor, Headwaters Resources, Inc., is the supporting operation and is located at 2723 East, 1500 North, Wheatfield, Indiana.

IDEM has determined that NIPSCO, Schahfer Station and Headwaters Resources, Inc., will be considered one source as defined by 326 IAC 2-7-1(22) based on contractual control. Therefore, the term “source” in the Part 70 documents refers to both NIPSCO, Schahfer Station and Headwaters Resources, Inc., as one source.

Separate Part 70 Operating permits will be issued to NIPSCO, Schahfer Station and Headwaters Resources, Inc., solely for administrative purposes.

Permitted Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units:

(a) One (1) cyclone coal-fired boiler identified as Unit 14, with construction commenced in 1970 and commercial operation begun in 1976, with a design heat input capacity of 4,650 million Btu per hour (MMBtu/hr), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter and exhausting to stack 14. Unit 14 has a selective catalytic reduction (SCR) system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 14 by 2014. The source plans to install and operate a Flue Gas Desulfurization System on Unit 14 by 2014.

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NO_X burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 15 by 2016. The source plans to install and operate a Selective Non-Catalytic Reduction (SNCR) system on Unit 15 by 2013 and a Flue Gas Desulfurization System on Unit 15 by 2016.

(c) One (1) dry bottom pulverized coal-fired boiler identified as Unit 17, with construction started in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 17 has been approved to fire blends of coal and petroleum coke.

(d) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, with construction started in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 18 has been approved to fire blends of coal and petroleum coke.

(e) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

(f) Coal storage and handling systems for Unit 14 and 15 boilers, constructed in 1972.

(1) Rail car unloading with wet suppression for PM control during unloading and enclosure for ancillary dust control.

(2) Coal pile unloading, coal storage pile(s), material handling equipment, and coal conveyors.

(3) Transfer House, with carryover wet suppression and enclosed transfer points within an enclosure for ancillary dust control, with an estimated throughput of 3,000 tons per hour.

(4) Crusher House, with carryover wet suppression for PM control and enclosed transfer points within an enclosure for ancillary dust control.

(5) Tripper House to tripper bays, with enclosed transfer points within an enclosure for dust control.

(6) Two (2) tripper bays with an estimated combined capacity of 3,000 tons per hour, with carryover wet suppression for PM control, each using an enclosure for ancillary dust control.

(g) Fuel storage and handling systems for Unit 17 and 18 boilers.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a multi-compartment baghouse for PM control.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) multi-compartment vent filters for PM control.

(h) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour.

(2) Two (2) ground limestone pneumatic truck unloading systems connected to Unit 17 limestone silos, with baghouses for PM control.

(3) Two (2) ground limestone pneumatic truck unloading systems connected to Unit 18 limestone silos, with baghouses for PM control.

(4) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour. All gypsum is handled wet.

(i) Dry fly ash handling and disposal.

(1) Pneumatic conveyance to storage silos, with a design capacity of 70 tons per hour of fly ash from Units 14 and 15 combined, and a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 14, 15, 17, and 18, with cyclone separators, silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads; and onsite disposal area.

(j) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(k) Ponded bottom ash handling/removal operations.

(l) Material handling for the flue gas desulfurization systems for Unit 14 and Unit 15 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Two (2) storage silos originally used for dual-alkali FGD system, with cyclone separators, silo collector bag filters, and bin vent bag filters. Ground limestone pneumatic truck unloading systems for Unit 14 and Unit 15 limestone silos, with integrated bin vent filter, to begin construction in 2011.

(3) Two (2) new conveyors to begin construction in 2011 for transfer of dewatered gypsum from belt filters to junction house.

(4) Two (2) new conveyors to begin construction in 2011 for transfer of dewatered gypsum from junction house to the existing gypsum conveying system.

(5) Transportation of off-specification gypsum by truck on unpaved roads.

(6) Pneumatic lime unloading system and storage silo at the existing wastewater treatment plant.

(7) Lime Transport Truck traffic on paved roads.

(m) One (1) diesel-fired, compression-ignited, 334 horsepower engine for a stationary fire pump system. It was constructed before July 11, 2005.

Emission Units and Pollution Control Equipment Constructed and/or Operated without a Permit

The source also consists of the following emission units that were constructed and/or are operating without a permit:

Emission Units and Pollution Control Equipment Removed From the Source

No emission units have been removed from this facility through this permitting action.

Insignificant Activities

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

(1) Conveyors as follows:

(A) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;

(B) 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;

(C) Uncovered coal conveying of less than or equal to 120 tons per day.

(D) Underground conveyors.

(2) Coal bunker and coal scale exhausts and associated dust collector vents.

(3) Space heaters or process heaters 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.

(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.

(4) Equipment powered by internal combustion engines of capacity equal to or less than 500,000 Btu/hour, except where total capacity of equipment operated by one stationary source exceeds 2,000,000 Btu/hour.

(5) Combustion source flame safety purging on startup.

(6) A gasoline fuel transfer and dispensing operation handling less than or equal to 1,300 gallons per day, such as filling of tanks, locomotives, automobiles, having a storage capacity less than or equal to 10,500 gallons.

(7) A petroleum fuel, other than gasoline, dispensing facility having a storage capacity less than or equal to 10,500 gallons, and dispensing less than or equal to 230,000 gallons per month.

(8) The following VOC and HAP storage containers:

(A) Storage tanks with capacity less than or equal to 1,000 gallons and annual throughput less than 12,000 gallons.

(B) Vessels storing lubricating oils, hydraulic oils, machining oils, and machining fluids.

(9) Equipment used exclusively for filling drums, pails or other packaging containers with lubricating oils, waxes, and greases.

(10) Application of oils, greases, lubricants, or other nonvolatile materials applied as temporary protective coatings.

(11) Machining where an aqueous cutting coolant continuously floods the machining interface.

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

(13) Cleaners and solvents characterized as follows:

(A) 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;

(B) 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.

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

(15) Closed loop heating and cooling systems.

(16) Any of the following structural steel and bridge fabrication activities:

(A) Cutting 200,000 linear feet or less of one inch (10) plate or equivalent.

(B) Using 80 tons or less of welding consumables.

(17) Solvent recycling systems with batch capacity less than or equal to 100 gallons.

(18) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume.

(19) Water runoff ponds for petroleum coke-cutting and coke storage piles.

(20) Activities associated with the transportation and treatment of sanitary sewage, provided discharge to the treatment plant is under the control of the owner/operator, that is, an on-site sewage treatment facility.

(21) Any operation using aqueous solutions containing less than 1% by weight of VOCs, excluding HAPs.

(22) Noncontact cooling tower systems with natural draft cooling towers not regulated under a NESHAP.

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

(24) Heat exchanger cleaning and repair.

(25) Process vessel degreasing and cleaning to prepare for internal repairs.

(26) Paved and unpaved roads and parking lots with public access.

(27) Asbestos abatement projects regulated by 326 IAC 14-10.

(28) Purging of gas lines and vessels that is related to routing maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process.

(29) Flue gas conditioning systems and associated chemicals such as the following: sodium sulfate, ammonia, and sulfur trioxide.

(30) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment.

(31) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

(32) On-site fire and emergency response training approved by the department.

(33) One (1) diesel-fired, compression-ignited, 334 horsepower engine for a stationary fire pump system, constructed before July 11, 2005. .[Under 40 CFR 60, Subpart IIII, emergency quench pumps are considered a new affected source]

(34) Other emergency equipment as follows: Stationary fire pumps.

(35) 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.

(36) Filter or coalescer media changeout.

(37) Vents from ash transport systems not operated at positive pressure.

(38) A laboratory as defined in 326 IAC 2-7-1(21)(D).

(39) Farm operations.

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

(a) Gasoline Storage Tanks

(b) Disposal of Boiler Chemical Cleaning wastes

(c) Battery Rooms

(d) Coal Pile Wind Erosion

(e) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill.

(f) Shot Blasters.

(g) Gypsum stockpile.

(h) Cold Cleaner degreasing operations. [326 IAC 8-3-2][326 IAC 8-3-5]

(i) One (1) Dibasic acid tank for the Unit 17 and 18 flue gas desulfurization systems, capacity 25,000 gallons, maximum throughput of 33.5 gallons of acid per hour to each unit.

(41) Two (2) diesel fired-engines for emergency quench pumps (model year 2011), each rated at 144 horsepower, to be permitted in 2012.[Under 40 CFR 60, Subpart IIII, emergency quench pumps is considered a new affected source]

Existing Approvals

Since the issuance of the Part 70 Operating Permit No.T073-6792-00008 on September 7, 2006, the source has constructed or has been operating under the following additional approvals:

(a) Appeal Resolution No. T 073-23745-00008 issued on May 7, 2008;

(b) Significant Source Modification No. T 073-26380-00008 issued on September 22, 2008;

(c) Significant Permit Modification No. T 073-26402-00008 issued on November 7, 2008; and

(d) Significant Permit Modification No. T 073-26398-00008, issued on April 4, 2009.

(e) Significant Source Modification No. T 073-30176-00008 issued on March 7, 2011;

(f) Significant Permit Modification No. T 073-30182-00008 issued on April 28, 2011;

(g) Temporary Operation No. 073-30960-00008 issued on September 29, 2011;

(h) Significant Permit Modification No. T 073-31215-00008 issued on February 23, 2012;

(i) Temporary Operation No. 073-31874-00008 issued on June 21, 2012; and

(j) Temporary Operation No. 073-31914-00008 issued on June 20, 2012.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

Enforcement Issue

There are no enforcement actions pending.

Emission Calculations

See Appendix A of this document for detailed emission calculations.

County Attainment Status

The source is located in Jasper County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective April 5, 2005, for PM2.5.	

(a) Ozone Standards

Volatile organic compounds (VOC) and Nitrogen Oxides (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. Jasper 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) $PM_{2.5}$

Jasper County has been classified as attainment for $PM_{2.5}$. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011 the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, June 28, 2011.. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability – Entire Source section.

(c) Other Criteria Pollutants

Jasper County has been classified as attainment or unclassifiable in Indiana for criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a power plant, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Unrestricted Potential Emissions

The numbers reported in the unrestricted potential emissions table of this TSD are based on certain assumptions and do not reflect the maximum allowable emissions from the plant. Accordingly, the information included in said tables, do not constitute enforceable conditions, and is not to be relied on in evaluating actual or allowable emissions from the plant.

Unrestricted Potential Emissions	
Pollutant	Tons/year
PM	> 142951
PM_{10}	> 32849
$PM_{2.5}$	> 32839
SO_2	241,400
VOC	278
CO	16,898
NOx	63,111
GHGs as CO2e	18,427,822
Single HAP	> 10
Total HAP	> 25

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM_{10}, $PM_{2.5}$, SO_2, VOC and NOx are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of GHGs is equal to or greater than one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

Actual Emissions

The following table shows the actual emissions from the source. This information reflects the 2010 OAQ emission data.

Pollutant	Actual Emissions (tons/year)
PM10	1,458
PM2.5	801
SO_2	27,065
VOC	202
CO	1,375
NOx	9,612
Ammonia	0
Lead	1.13

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM	PM10*	PM2.5	SO_2	VOC	CO	NOx	GHG as CO2e	Total HAPs
Cyclone Boiler Unit 14	88.6	484	484	5313	97.4	443	29222	4581097	1207
Dry bottom pulverized boiler Unit 15	54282	12485	12485	6031	60	1639	11057	4844241	1362
Dry bottom pulverized boiler Unit 17	524	9711	9711	10790	47	4691	9383	3759709	1059.6
Dry bottom pulverized boiler Unit 18	524	9711	9711	10790	47	4691	9383	3759709	1059.6
Combustion Turbine Unit 16A	42	42	42	22	13.3	521	2032	741533	6.2
Combustion Turbine Unit 16B	42	42	42	22	13.3	521	2032	741533	6.2
Coal Storage and Handling for Unit 14 & 15 Boilers	33.3	12	12	0	0	0	0	0	0
Fuel Storage and Handling for Unit 17 & 18 Boilers	> 25	> 15	> 10	0	0	0	0	0	0
Material Handling for Unit 17 and 18	131	131	131	0	0	0	0	0	0
Dry ash handling and disposal	209	209	209	0	0	0	0	0	0
Material Handling for Unit 14 and 15									

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM	PM10*	PM2.5	SO_2	VOC	CO	NOx	GHG as CO2e	Total HAPs
Limestone Drop Point - Fugitive	2.32	1.1	0.17	0	0	0	0	0	0
Gypsum Drop Point - Fugitive	2.83	1.34	0.20	0	0	0	0	0	0
Storage Pile Maintenance	4.35	2.18	0.87	0	0	0	0	0	0
Limestone Vehicle Traffic	5.35	1.07	0.26	0	0	0	0	0	0
Gypsum Vehicle Traffic	6.6	1.68	0.168	0	0	0	0	0	0
Emergency generator	0.05	0.03	0.03	0.29	0.05	0.4	1.73	83.8	0.0008
Total PTE of Entire Source	**> 55923**	**> 32849**	**> 32839**	**32967**	**278**	**12506**	**63,111**	**18,427,822**	**> 10** **> 25**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100000	10/25
PSD Major Source Thresholds	100	100	100	100	100	100	100	100000	NA

negl. = negligible
*Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), not particulate matter (PM), is considered as a "regulated air pollutant".

Notes:

The numbers reported in the Potential to Emit Table above are based on certain assumptions and therefore, does not reflect the maximum allowable emissions from the plant. Accordingly, the information included in the Table, does not constitute enforceable conditions, and is not to be relied on in evaluating actual or allowable emissions from the plant.

This existing stationary source is major for PSD because the emissions of at least one regulated pollutant are greater than one hundred (>100) tons per year, 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 in one of the twenty-eight (28) listed source categories.

Federal Rule Applicability

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each existing emission unit and specified pollutant subject to CAM:

Emission Unit / Pollutant	Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Unit 14 (PM10)	Y	N	484	< 100	100	N	N
Unit 14 (PM)	Y	Y	3719	< 100	100	Y	N
Unit 14 (PM2.5)	Y	N	484	< 100	100	N	N
Unit 15 (PM10)	Y	N	12485	> 100	100	N	Y
Unit 15 (PM)	Y	Y	54282	> 100	100	Y	Y
Unit 15 (PM2.5)	Y	N	12485	> 100	100	N	Y
Unit 17 (PM10)	Y	N	9711	< 100	100	N	N
Unit 17 (PM)	Y	Y	42223	> 100	100	Y	Y
Unit 17 (PM2.5)	Y	N	9711	< 100	100	N	N
Unit 18 (PM10)	Y	N	9711	< 100	100	N	N
Unit 18 (PM)	Y	Y	42223	> 100	100	Y	Y
Unit 18 (PM2.5)	Y	N	9711	< 100	100	N	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to Units 14, 15, 17 and 18 for PM. A CAM plan has been incorporated into the permit has an attachment. All the Boilers have COMs which will satisfy the large unit requirements.

Pursuant to 40 CFR 64.2(b)(1)(vi), the requirements of 40 CFR Part 64 (CAM) shall not apply to emission limitations or standards for which a Part 70 permit specifies a continuous compliance determination method. Since compliance with the NOx and SO_2 emission limitations in the Part 70 permit is specified to be determined by continuous emissions monitoring systems (CEMS), CAM is not applicable to Boilers 14, 15 17 and 18 for NOx and SO_2 emissions. All other emission units have uncontrolled emissions less than the major source threshold.

(b) The Boiler, identified as Unit 14 is not subject to the requirements of the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subparts D, Db, and Dc, Standards of Performance for Fossil-Fuel-Fired Steam Generators and Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), because construction commenced before August 17, 1971. Physical construction of Unit 14 began in 1972;

however, the date of the commencement of construction for this unit has previously been determined to be April 1, 1970, the date that the boiler was ordered.

(c) The combustion turbines, identified as 16A and 16B are not subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY. Pursuant to 40 CFR 63.6090(a)(1) each turbine meets the criteria of an "existing stationary combustion turbine" because construction was commenced on each turbine prior to January 14, 2003. Pursuant to 40 CFR 63.6090(b)(4), existing stationary combustion turbines do not have to meet the requirements of 40 CFR 63, Subpart YYYY and of 40 CFR 63, Subpart A. Therefore, the emission unit is not subject to this rule.

(d) The limestone handling for the Unit 17 and 18 FGD system, limestone and gypsum material handling systems are not subject to the requirements of the New Source Performance Standard, 326 IAC 12 (40 CFR 60, Subpart OOO, (Standards of Performance for Nonmetallic Mineral Processing Plants) because these handling operations do not meet the definition for a nonmetallic mineral processing plant. There is no crushing of limestone performed onsite, only storage and conveying. All limestone is received in powdered form. Therefore, the requirements of this rule are not applicable to these emission units.

(e) The gasoline and distillate oil storage tanks are not subject to the requirements of the New Source Performance Standard, 326 IAC 12 (40 CFR 60, Subpart K, (Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and prior to May 19, 1978); because all of the tanks were installed prior to 1984, and have not been reconstructed or modified. The exact date of installation is not known; however, Subparts K specifically exempt Nos. 2 through 6 fuel oils from the definition of Petroleum Liquids.

(f) The gasoline and distillate oil storage tanks are not subject to the requirements of the New Source Performance Standard, 326 IAC 12 (40 CFR 60, Subpart Ka (Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and prior to July 23, 1984) because all of the tanks were installed prior to 1984, and have not been reconstructed or modified. The exact date of installation is not known; however, Subparts Ka specifically exempt Nos. 2 through 6 fuel oils from the definition of Petroleum Liquids.

(g) The boiler, identified as Unit 15 is subject to the requirements of the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971)), because the heat input rate is 5100 MMBTU/hr, and construction has been determined to have commenced on or about June 25, 1974, based on the date of the performance guarantee submitted with the construction permit application for the unit. The emission unit subject to the rule is as follows:

(1) One (1) dry bottom pulverized coal-fired boiler identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NO_X burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. The Source plans to install a Reagent Injection System on Unit 15 by 2016. The source plans to install and operate a Selective Non-Catalytic Reduction (SNCR) system on Unit 15 by 2013 and a Flue Gas Desulfurization System on Unit 15 by 2016.

The emission unit is subject to the following portions of Subpart D.

(1) 40 CFR 60.40(a) & (c)
(2) 40 CFR 60.42(a)
(3) 40 CFR 60.43(a), (b) & (c)
(4) 40 CFR 60.44(a)(1-3)&(b)
(5) 40 CFR 60.45
(6) 40 CFR 60.46

(h) The boilers, identified as Units 17 and 18 are subject to the requirements of the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)), because the design heat input rate of each unit is 3967 MMBTU/hr and construction of both units began in April 1980. The emission units subject to the rule are as follows:

(1) One (1) dry bottom pulverized coal-fired boiler identified as Unit 17, with construction started in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 17 has been approved to fire blends of coal and petroleum coke.

(2) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, with construction started in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitoring (COM) system. Unit 18 has been approved to fire blends of coal and petroleum coke.

The applicable Subpart Da requirements include:

(1) 40 CFR 60.40da(a)
(2) 40 CFR 60.42da(a)&(b)
(3) 40 CFR 60.43da(a),(b),&(h)
(4) 40 CFR 60.44da(a)
(5) 40 CFR 60.48da(a),(b),(d),(e),(h),(q),&(s)
(6) 40 CFR 60.49da(a)(1),(b)(1),(b)(4),(c),(d),(e),(f)(1),(g),(h),(i),(j),(s),&(w)
(7) 40 CFR 60.50da(a).(b)(1),(b)(3),(c),(d),&(e)
(8) 40 CFR 60.51da(a),(b),(c),(i),(j),&(k)

(i) The fuel storage and handling systems for Units 17 and 18 are subject to the New Source Performance Standard - Standards of Performance for Coal Preparation and Processing Plants, 40 CFR 60, Subpart Y, which is incorporated by reference as 326 IAC 12. The emission units are subject to the requirements of this rule because the source is involved in coal preparation and processing plants that process more than 200 tons of coal per day and commenced reconstruction and modification after October 27, 1974, and on or before April 28, 2008. The emission units subject to the rule are as follows:

(1) Fuel storage and handling systems for Unit 17 and 18 boilers.

The emission unis are subject to the following portions of Subpart Y.

(1) 40 CFR 60.250(a)&(b)
(2) 40 CFR 60.254(a)
(3) 40 CFR 60.255(a)

(j) The (2) natural gas-fired combustion turbines, identified as 16A and 16B are subject to the New Source Performance Standard - Standards of Performance for Stationary Gas Turbines, 40 CFR 60, Subpart GG, which is incorporated by reference as 326 IAC 12. The emission units are subject to the requirements of this rule because the heat input at peak load equal to or greater than 10 million Btu per hour and the source commences construction, modification, or reconstruction after October 3, 1977. Therefore, the emission units subject to the rule are as follows:

(1) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

The emission units are subject to the following portions of Subpart GG.

(1) 40 CFR 60.330
(2) 40 CFR 60.332(a)&(f)
(3) 40 CFR 60.333
(4) 40 CFR 60.334
(5) 40 CFR 60.335

(k) The requirements of the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) (40 CFR 63, Subpart ZZZZ), (326 IAC 20-82) are included in this permit for the existing emergency stationary RICE less than 500 HP (manufactured before June 12, 2006),located at a major source of HAP emissions.

These emission units are subject to the following portions of Subpart ZZZZ:

(1) One (1) diesel-fired, compression-ignited, 334 horsepower engine for a stationary fire pump system. It was constructed before July 11, 2005.

These emission unit is subject to the following portions of Subpart ZZZZ:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(1)(ii),(b)(3)(iii),&(c)(7)
(4) 40 CFR 63.6595(a)(1)
(5) 40 CFR 63.6602
(6) 40 CFR 63.6605
(7) 40 CFR 63.6625(e),(f),(h),&(i)
(8) 40 CFR 63.6640(f)
(9) 40 CFR 63.6645(a)(1)&(a)(5)
(10) 40 CFR 63.6655(d),(e)(2),&(f)(1)
(11) 40 CFR 63.6660
(12) 40 CFR 63.6665
(13) Table 2(c), #1, of Subpart ZZZZ of Part 63
(14) Table 6, #9, of Subpart ZZZZ of Part 63

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63 Subpart ZZZZ.

(l) The diesel fired-engines for emergency quench pumps are subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60.4200, Subpart IIII), which is incorporated by reference as 326 IAC 12 because the emergency generator is constructed after 2007. The units subject to this rule include the following:

(1) Two (2) diesel fired-engines for emergency quench pumps(model year 2011), each rated at 144 horsepower, to be permitted in 2012.[Under 40 CFR 60, Subpart IIII, emergency quench pumps is considered a new affected source]

The emergency generator and the firewater pumps are subject to the following sections of 40 CFR Part 60, Subpart IIII.

(1) 40 CFR 60.4200(a)(2)(ii);
(2) 40 CFR 60.4205(c);
(3) 40 CFR 60.4206;
(4) 40 CFR 60.4207(a);
(5) 40 CFR 60.4207(b);
(6) 40 CFR 60.4209(a);
(7) 40 CFR 60.4211(a);
(8) 40 CFR 60.4211(c);
(9) 40 CFR 60.4211(f);
(10) 40 CFR 60.4211(g)(2);
(11) 40 CFR 60.4214(b);
(12) 40 CFR 60.4218;
(13) Table 3 to Subpart IIII of Part 60
(14) Table 4 to Subpart IIII of Part 60
(15) Table 8 to Subpart IIII of Part 60

(m) The requirements of the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) (40 CFR 63, Subpart ZZZZ), (326 IAC 20-82) are applicable to a Stationary Reciprocating Internal Combustion Engines (RICE) at a major or area source of HAP emissions. In accordance with 40 CFR 63.6590(c)(7), a new emergency stationary RICE with a site rating of less than 500 hp located at a major source of HAP that meet the requirements of 40 CFR Part 60 Subpart IIII is not subject to the requirements of this rule. Since the diesel engine emergency quench pump will meet the requirements of 40 CFR Part 60 Subpart IIII, these units are exempt from the requirements of this rule.

(n) Clean Air Interstate Rule (CAIR)
The cyclone coal-fired boiler, identified as Unit 14 and the bottom pulverized coal-fired boilers, identified as Unit 15, Unit 17, Unit 18 and the two natural gas-fired combustion turbines, identified as 16A and 16B are subject to the Clean Air Interstate Rule (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 40 CFR 97.

(o) Acid Deposition Control
326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is subject to the requirements of 326 IAC 21 and shall be incorporated into the permit.

State Rule Applicability - Entire Source

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))
This source is one of the 28 listed source categories and has potential to emit of at least one regulated pollutant greater than 100 tons per year before August 7, 1977. This source was a major source pursuant to 326 IAC 2-2 (PSD), prior to August 7, 1977.

326 IAC 2-2 (Alternative Fuel Blends)

(a) Pursuant to a letter from IDEM, OAQ, to NIPSCO dated June 13, 1996, based on the results of emissions testing performed in 1995 and subsequent ambient air modeling studies, petroleum coke may be combusted in Units 17 and 18 at a blend rate of no more than 30 percent (30%) petcoke (by weight). The conditions of the Units 17 and 18 federal PSD construction permit are not affected by this ruling, and all requirements contained therein still apply.

(b) The flue gas desulfurization (FGD) system shall be in operation at all times when pet coke is being fired. Should an emergency condition occur which causes a malfunction of the FGD system, the Permittee shall cease bunkering pet coke until the FGD system is fully operational.

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

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to PSD/Significant Permit Modification 073-26402-00008 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the source is subject to the requirements of 326 IAC 2-2-3, Best Available Control Technologies (BACT), for the following units;

Cyclone coal-fired boiler Unit 14, dry bottom pulverized coal-fired boiler Unit 15, Unit 17, Unit 18, two (2) natural gas-fired combustion turbines Unit 16A and 16B, fuel storage and handling system, fly ash handling storage and transport and bottom ash handling, storage and transport.

326 IAC 2-6 (Emission Reporting)
This source is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of PM10 is greater than 250 tons per year, and the potential to emit of NOx and SO2 is greater than 2,500 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted by July 1, 2013, and every year thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(2)

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

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
This rule is not applicable because the source is not located in a nonattainment area, and obtained all necessary approvals before December 13, 1985.

326 IAC 7-3 (Ambient Monitoring)
The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted to the commissioner for approval. The monitoring plan shall include requirements listed in 326 IAC 7-3-2(a)(1), 326 IAC 7-3-2(a)(2) and 326 IAC 7-3-2(a)(3).

State Rule Applicability – Individual Facilities

326 IAC 3-5 (Continuous Emission Monitoring)
Pursuant to 326 IAC 3-5-1(b)(2), the boiler, identified as Unit 14, Unit 15, Unit 17 and Unit18 are subject to the requirements of 326 IAC 3-5 because they are coal-fired steam generator of greater than one hundred million (100,000,000) British thermal units (Btus) per hour heat input capacity.

326 IAC 5-1-3 (Temporary Alternative Opacity Limitations)
(a) Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the boiler, identified as Unit 14 and Unit 15 are subject to the requirements of 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations).

Note: Unit 15 is not subject to 326 IAC 5-1-3(b), Temporary Alternative Opacity Limitations, when removing ashes from the fuel bed or furnace or when blowing tubes, because the opacity limit established by 40 CFR 60 Subpart D does not exempt these times.

(b) The boilers, identified as Unit 17 and 18 are not subject to the requirements of 326 IAC 5-1-3 (Temporary Alternative Opacity Limitation) because the opacity limit established in the PSD permit did not exempt any periods of time, including startup or shutdown. Also, the opacity limit established by 40 CFR 60 Subpart Da does not exempt times of removing ashes from the fuel bed or furnace or blowing tubes.

326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect heating)
(a) Pursuant to 326 IAC 6-2-4(b) and Operation Permit 37-05-91-0102, issued on September 14, 1988, the particulate matter (PM) emissions to the atmosphere from the boiler, identified as Unit 14 shall not exceed 0.1 pounds per million Btu (lb/MMBTU) of energy input.

This limit is more stringent than the value that would be derived using the stack configuration information for the stacks in use on June 8, 1972 and the equation in 326 IAC 6-2-3(a); therefore, compliance with this limit will satisfy the requirements of 326 IAC 6-2.

(b) Pursuant to 326 IAC 6-2 and Operation Permit 37-05-91-0102, issued on September 14, 1988, the boiler, identified as unit No. 14 shall not exceed a maximum hourly average of 431 megawatts net (468 megawatts gross) until such time as stack testing indicates compliance with the applicable PM and opacity limitations at a higher level. The Permittee may request a temporary exemption in accordance with 326 IAC 2-1.1-3(g)(3) for stack testing at a higher capacity.

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

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes) the allowable PM emission rate from the coal handling system shall not exceed 58.5 pounds per hour when operating at a process weight rate of 200 tons per hour.

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

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

Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes) the coal handling system operating at a process weight rate of 200 tons per hour, the maximum allowable emission may exceed 58.5 pounds per hour, provided the concentration of particulate in discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1000) pounds of gases.

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes) the allowable PM emission rate from the storage and handling systems for Unit 17 and 18 shall not exceed 58.5 pounds per hour when operating at a process weight rate of 200 tons per hour.

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

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

Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes) the coal handling system operating at a process weight rate of 200 tons per hour, the maximum allowable emission may exceed 58.5 pounds per hour, provided the concentration of particulate in discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1000) pounds of gases.

(c) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the fly ash conveyance from Units 14 and 15 shall not exceed 47.8 pounds per hour when operating at a process weight rate of 70 tons per hour of ash, and the particulate emission rate from the fly ash conveyance from each of Units 17 and 18 shall not exceed 46.8 pounds per hour when operating at a process weight rate of 63 tons per hour of fly ash from each of Units 17 and 18. These pounds per hour limitations were calculated using the following equation:

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

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

(d) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the limestone handling systems and gypsum transfer systems shall not exceed 30 pounds per hour when operating at a process weight rate of 38,941 pounds per hour. This pounds per hour limitation was calculated using the following equation:

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 P = process weight rate in tons per hour.

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

(f) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), 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:

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 P = process weight rate in tons per hour.

(g) All of the bottom ash is always processed wet. Therefore, there are no particulate emissions from these operations, therefore, the requirements of 326 IAC 6-3-2 is not applicable to the bottom ash.

The control devices shall be in operation at all times the emission units are in operation, in order to comply with these limits.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
This boilers, identified as Unit 14, Unit 15 are subject to 326 IAC 326 IAC 7-1.1 because its SO_2 PTE is equal to or greater than 25 tons per year or 10 pounds per hour.

(A) **Unit 14**

(1) Pursuant to 326 IAC 7.1.1-2(a)(3), sulfur dioxide emissions from Unit 14 shall not exceed 0.5 pounds per million Btu's (lb/MMBtu) when combusting only distillate oil or only distillate oil and natural gas.

(2) Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from Unit 14 shall not exceed six and zero-tenths (6.0) pounds per million Btu for coal combustion.

(3) Pursuant to 326 IAC 7-1.1-2(b), sulfur dioxide emissions from Unit 14 shall not exceed six and zero-tenths (6.0) pounds per million Btu when combusting coal and oil simultaneously.

(B) **Unit 15**

(1) Pursuant to 326 IAC 7.1.1-2(a)(3), sulfur dioxide emissions from Unit 15 shall not exceed five-tenths (0.5) pound per million Btu's (lb/MMBtu) when combusting only distillate oil or only distillate oil and natural gas.

(2) Pursuant to 326 IAC 7-1.1-2(a)(1), sulfur dioxide emissions from Unit 15 shall not exceed six and zero-tenths (6.0) pounds per million Btu for coal combustion.

(3) Pursuant to 326 IAC 7-1.1-2(b), sulfur dioxide emissions from Unit 15 shall not exceed six and zero-tenths (6.0) pounds per million Btu when combusting coal and oil simultaneously.

(C) The boilers, identified as Unit 17 and 18 are subject to the requirements of 326 IAC 326 IAC 7-1.1 because there SO_2 PTE are equal to or greater than 25 tons per year or 10 pounds per hour. The units are subject to the requirements of 326 IAC 2-2-3 (PSD) and this will satisfy for this requirements.

(D) This emergency generator is not subject to 326 IAC 326 IAC 7-1.1 because its SO_2 PTE is less than 25 tons/year or 10 pounds/hour. Therefore, the requirements of 326 IAC 7-1.1 do not apply to this emergency generator.

326 IAC 8-3-2 (Cold Cleaner Operations)
The cold cleaning operations are subject to 326 IAC 8-3-2 (Cold Cleaner Operations). This rule applies to cold cleaner type degreasing facilities constructed after January 1, 1980 and before July 1, 1990. The cold cleaning operations at this source were constructed after 1980, therefore, the requirements of 326 IAC 8-3-2 shall apply to these facilities.

326 IAC 8-3-5 (Cold Cleaner Degreaser Operation and Control)
The cold cleaning operations are subject to 326 IAC 8-3-5 (Cold Cleaner Degreaser Operation and Control). This rule applies to cold cleaner type degreasing facilities constructed after July 1, 1990 without remote solvent reservoirs and located in Clark, Elkhart, Floyd, Lake Marion, Porter or St.Joseph Counties. The cold cleaning operations at this source were constructed after July 1 1990, therefore, the requirements of 326 IAC 8-3-5 shall apply to these facilities.

326 IAC 10-4 NOx Budget Trading Program
The Nitrogen Oxide budget trading program is no longer applicable to any control period in 2009 or thereafter. Therefore, pursuant to 326 IAC 10-4-16(a), IDEM, OAQ, has removed Section F - Nitrogen Oxides Budget Trading Program in its entirety from the permit.

326 IAC 24 (Clean Air Interstate Rule (CAIR))
The cyclone coal-fired boiler, identified as Unit 14 and the bottom pulverized coal-fired boilers, identified as Unit 15, Unit 17, Unit 18 and the two natural gas-fired combustion turbines, identified as 16A and 16B are subject to the Clean Air Interstate Rule (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a).

326 IAC 21 Acid Deposition Control
326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is subject to the requirements of 326 IAC 21.

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 monitoring requirements applicable to this source are as follows:

Emission Unit	Control Device	Pollutant	Frequency of Testing	Limits and Requirements
Boiler Unit 14 and 15	ESP	PM	2 years	326 IAC 6-2-3 and 40 CFR 60 Subpart D
Boiler Unit 17 or 18	ESP	PM	2 years	326 IAC 2-2-3 and 40 CFR 60 Subpart Da
Boiler Unit 15	LNB	CO	5 years	326 IAC 2-2-3

The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Range	Excursions and Exceedances	Limits and Requirements
Units 14, 15, 17 and 18 (ESP)	T-R set in service and T-R electrical values of Primary and secondary voltages and currents.	Daily	Not Applicable	Response Steps	326 IAC 6-2-2
Coal Crusher (Baghouse)	Water Pressure Drop	Weekly	2.0 to 8.0 inches	Response Steps	326 IAC 2-2 and 326 IAC 6-3-2
	Visible Emissions		Normal-Abnormal		
Ash Handling (Baghouse)	Water Pressure Drop	Daily	1.0 to 12.0 inches	Response Steps	326 IAC 2-2 and 326 IAC 6-3-2
	Visible Emissions		Normal-Abnormal		

Control	Parameter	Frequency	Range	Excursions and Exceedances	Limits and Requirements
Rail Car Unloading Station	Visible emission notations	Daily	Normal/Abnormal	Response steps	326 IAC 6-3-2
Fuel transfer Exhaust	Visible emission notations	Weekly	Normal/Abnormal	Response steps	326 IAC 6-3-2
Coal Crusher	Visible emission notations	Weekly	Normal/Abnormal	Response steps	326 IAC 6-3-2
Ash Silo Unloading Station	Visible emission notations	Daily	Normal/Abnormal	Response steps	326 IAC 6-3-2
fly ash conveyance, silo bag filter, and the bin vent filter	Visible emission notations	Daily	Normal/Abnormal	Response steps	326 IAC 6-3-2
nozzle of each telescoping chute	Visible emission notations	Daily	Normal/Abnormal	Response steps	326 IAC 6-3-2
Landfill Area	Visible emission notations	Daily	Normal/Abnormal	Response steps	326 IAC 6-3-2
storage pond in the Waste Disposal Area or the Material Storage Runoff Pond area that contains either bottom ash and/or FGD sludge	Visible emission notations	Weekly	Normal/Abnormal	Response steps	326 IAC 6-3-2

Recommendation

The staff recommends to the Commissioner that the Part 70 Operating Permit Renewal be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on December 8, 2010.

Conclusion

The operation of this electric utility plant shall be subject to the conditions of the attached Part 70 Operating Permit Renewal No. 073-29983-00008.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317-234-5257) or toll free at 1-800-451-6027 extension (4-5257).

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.idem.in.gov

Appendix A: Emissions Calculations
Emission Summary

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Uncontrolled Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit									
Cyclone Boiler Unit 14	3719	484	484	16825	97.4	443	29222	4581097	1207
Pulverized Boiler Unit 15	54282	12485	12485	87856	60	6031	11057	4844241	1362
Pulverized Boiler Unit 17	42223	9711	9711	68338	47	4691	9383	3759709	1059.6
Pulverized Boiler Unit 18	42223	9711	9711	68338	47	4691	9383	3759709	1059.6
Natural gas Combustion Turbine Unit 16A	41.9	41.9	41.9	21.6	13.3	520.8	2032	741533	6.2
Natural gas Combustion Turbine Unit 16B	41.9	41.9	41.9	21.6	13.3	520.8	2032	741533	6.2
Coal Storage and Handling for Unit 14 and 15 Boilers	33.27	11.6	11.6	0	0	0	0	0	0
Fuel Storage and handling Unit 17 and 18	> 25	> 15	> 10	0	0	0	0	0	0
Material Handling Unit 17 and 18	131.4	131.4	131.4	0	0	0	0	0	0
Dry Fly Ash Handling and Disposal	209	209	209	0	0	0	0	0	0
Material Handling for Unit 14 and 15									
Limestone Drop Point - Fugitive	2.32	1.1	0.17	0	0	0	0	0	0
Gypsum Drop Point - Fugitive	2.83	1.34	0.2	0	0	0	0	0	0
Storage Pile Maintenance	4.35	2.177	0.871	0	0	0	0	0	0
Limestone Vehicle Traffic	5.35	1.07	0.263	0	0	0	0	0	0
Gypsum Vehicle Traffic	6.61	1.68	0.17	0	0	0	0	0	0
Two (2) Emergency Generators	0.05	0.03	0.03	0.29	0.05	0.4	1.73	83.8	0.0008
Total Emissions	> 142951	> 32849	> 32839	241400	278	16898	63111	18427906	Single HAP >10 Combined HAPs > 25

Appendix A: Emissions Calculations

Emission Summary

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Limited Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit									
Cyclone Boiler Unit 14	88.6	484	484	5313	97.4	443	29222	4581097	1207
Pulverized Boiler Unit 15	54282	12485	12485	6031	60	1639	11057	4844241	1362
Pulverized Boiler Unit 17	524	9711	9711	10790	47	4691	9383	3759709	1059.6
Pulverized Boiler Unit 18	524	9711	9711	10790	47	4691	9383	3759709	1059.6
Natural gas Combustion Turbine Unit 16A	41.9	41.9	41.9	21.6	13.3	520.8	2032	741533	6.2
Natural gas Combustion Turbine Unit 16B	41.9	41.9	41.9	21.6	13.3	520.8	2032	741533	6.2
Coal Storage and Handling for Unit 14 and 15 Boilers	33.27	11.6	11.6	0	0	0	0	0	0
Fuel Storage and handling Unit 17 and 18				0	0	0	0	0	0
Material Handling Unit 17 and 18	131.4	131.4	131.4	0	0	0	0	0	0
Dry Fly Ash Handling and Disposal	209	209	209	0	0	0	0	0	0
Material Handling for Unit 14 and 15									
Limestone Drop Point - Fugitive	2.32	1.1	0.17	0	0	0	0	0	0
Gypsum Drop Point - Fugitive	2.83	1.34	0.2	0	0	0	0	0	0
Storage Pile Maintenance	4.35	2.177	0.871	0	0	0	0	0	0
Limestone Vehicle Traffic	5.35	1.07	0.263	0	0	0	0	0	0
Gypsum Vehicle Traffic	6.61	1.68	0.17	0	0	0	0	0	0
Two (2) Emergency Generators	0.05	0.03	0.03	0.29	0.05	0.4	1.73	83.8	0.0008
Total Emissions	> 55923	> 32849	> 32838	32967	278	12506	63111	18427822	Single HAP > 10 Combined HAPs > 25

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #14

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal	Potential Throughput tons/year
4650	11,500	1,771,043

Weight % Sulfur in Fuel	Weight % Ash in Fuel
0.500	2.1

	Pollutant						
	PM*	PM10*	PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	4 (2A)	1 (0.26A)	1 (0.26A)	19.0 *(38S)*	33.0	0.11	0.5
Potential Emission in tons/yr	3719.2	483.5	483.5	16824.9	29222.2	97.4	442.8

Emission Factors are from AP-42, Table 1.1-3, 1.1-4 and 1.1-5 (09/98) for Cyclone bituminous
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Assume the Heating value of the coal used at this plant is 23.868 MMBtu/ton

Methodology

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	5133	1	0
Potential Emission, ton/yr	4,545,714	535	78
Summed Potential Emissions, tons/yr	4,546,327		
l Warming Potential (100 Year)	1	21	310
CO2e Total in tons/yr	4,581,097		

Methodology

Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton

Emission Factors from Tables C-1 and 2 of 40 CFR Part 98 Subpart C and have been converted from kg/MMBtu to lb/ton.

Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Appendix A: Emission Calculations
Coal Burning - HAP Emissions Unit #14

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Emission Units:	**Boiler 14**
Max.Total Heat Input Capacity (MMBtu/hr):	**1,638**
Max Coal Input Capacity (tons/hr):	**202.2**

Pollutant	Emission Factor (lbs/ton of Coal)	PTE of HAP (tons/yr)
Acetaldehyde	5.70E-04	5.0E-01
Acetophenone	1.50E-05	1.3E-02
Acrolein	2.90E-04	2.6E-01
Benzene	1.30E-03	1.2E+00
Benzyl Chloride	7.00E-04	6.2E-01
DEHP	7.30E-05	6.5E-02
Bromoform	3.90E-05	3.5E-02
Carbon Disulfide	1.30E-04	1.2E-01
2-Chloroacetophenone	7.00E-06	6.2E-03
Chlorobenzene	2.20E-05	1.9E-02
Chloroform	5.90E-05	5.2E-02
Cumene	5.30E-06	4.7E-03
Cyanide	2.50E-03	2.2E+00
2,4-Dinitrotoluene	2.80E-07	2.5E-04
Dimethyl Sulfate	4.80E-05	4.3E-02
Ethyl Benzene	9.40E-05	8.3E-02
Ethyl Chloride	4.20E-05	3.7E-02
Ethylene Dichloride	4.00E-05	3.5E-02
Ethylene Dibromide	1.20E-06	1.1E-03
Formaldehyde	2.40E-04	2.1E-01
Hexane	6.70E-05	5.9E-02
Isophorone	5.80E-04	5.1E-01
Methyl Bromide	1.60E-04	1.4E-01
Methyl Chloride	5.30E-04	4.7E-01
Methyl Hydrazine	1.70E-04	1.5E-01
Methyl Methacrylate	2.00E-05	1.8E-02
Methyl Tert Butyl Ether	3.50E-05	3.1E-02
Methylene Chloride	2.90E-04	2.6E-01
Phenol	1.60E-05	1.4E-02
Propionaldehyde	3.80E-04	3.4E-01
Tetrachloroethylene	4.30E-05	3.8E-02
Toluene	2.40E-04	2.1E-01
1,1,1-Trichloroethane	2.00E-05	1.8E-02
Styrene	2.50E-05	2.2E-02
Xylenes	3.70E-05	3.3E-02
Vinyl Acetate	7.60E-06	6.7E-03
Antimony	1.80E-05	1.6E-02
Arsenic	4.10E-04	3.6E-01
Beryllium	2.10E-05	1.9E-02
Cadmium	5.10E-05	4.5E-02
Chromium	2.60E-04	2.3E-01
Chromium (VI)	7.90E-05	7.0E-02
Cobalt	1.00E-04	8.9E-02
Lead	4.20E-04	3.7E-01
Manganese	4.90E-04	4.3E-01
Mercury	8.30E-05	7.4E-02
Nickel	2.80E-04	2.5E-01
Selenium	1.30E-03	1.2E+00
Hydrogen Fluoride	1.50E-01	132.8
Hydrogen Chloride	1.20E+00	1062.8
Total		**1,206.51**

Note: Emission factors from AP-42, Tables 1.1-13, 1.1-14, 1.1-15, and 1.1-18 for Coal Combustion (09/98).

Methodology

PTE of HAP (tons/yr) = Max. Total Heat Input (MMBtu/hr) / 23.868 MMBtu/ton x Emission Factor (lbs/ton) x 8760 hrs/yr x 1 ton/2,000 lbs

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #15

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
5100	11111	2.01E+06

	Weight %
Sulfur =	2.3
Ash =	5.40

Uncontrolled PTE	Pollutant (tons per year)					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/ton	54.0 *(10A)*	12.42 *(2.3A)*	87.4 *(38S)*	11.0	0.06	6.00
Potential Emission in tons/yr	54,282	12,485	87,856	11,057	60	6,031

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	1206.3	150.8	1.3	0.7	2.5	0.6

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/ton	6.84E+02	8.10E+01	1.57E+03	5.07E+02	2.98E+03	1.29E+03
Potential Emission in tons/yr	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion.
SCC 1-01-002-05/21
SCC 1-02-002-06/22
SCC 1-03-002-06/22

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #17

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %
Sulfur =	2.3

	Weight %
Ash =	5.40

Uncontrolled PTE	Pollutant (tons per year)					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/ton	54.0 *(10A)*	12.42 *(2.3A)*	87.4 *(38S)*	12.0	0.06	6.00
Potential Emission in tons/yr	42,223	9,711	68,338	9,383	47	4,691

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/ton	6.84E+02	8.10E+01	1.57E+03	5.07E+02	2.98E+03	1.29E+03
Potential Emission in tons/yr	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion.
SCC 1-01-002-05/21
SCC 1-02-002-06/22
SCC 1-03-002-06/22

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %
Sulfur =	2.3

	Weight %
Ash =	5.40

Uncontrolled PTE	Pollutant (tons per year)					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/ton	54.0 *(10A)*	12.42 *(2.3A)*	87.4 *(38S)*	12.0	0.06	6.00
Potential Emission in tons/yr	42,223	9,711	68,338	9,383	47	4,691

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/ton	6.84E+02	8.10E+01	1.57E+03	5.07E+02	2.98E+03	1.29E+03
Potential Emission in tons/yr	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00	0.0.E+00

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion.

SCC 1-01-002-05/21
SCC 1-02-002-06/22
SCC 1-03-002-06/22

Emission Summary
Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Coal Emissions							
Emission Unit	**Coal Throughput (ton/yr)**	**CO_2 Emission Factor (lb/ton)**	**CH_4 Emission Factor (lb/ton)**	**N_2O Emission Factor (lb/ton)**	**CO_2 Emissions (ton/yr)**	**CH_4 Emissions (ton/yr)**	**N_2O Emissions (ton/yr)**
Boiler Unit 15	2,010,000	4,810	0.04	0.03	4,834,050	40	30
Boiler Unit 17	1,560,000	4,810	0.04	0.03	3,751,800	31	23
Boiler Unit 18	1,560,000	4,810	0.04	0.03	3,751,800	31	23

Greenhouse Gas Emissions - CO_2e Calculation							
	Worst Case Emissions			**Global Warming Potential**			**CO_2e (TPY)**
	CO_2 Emissions (ton/yr)	**CH_4 Emissions (ton/yr)**	**N_2O Emissions (ton/yr)**	**CO_2 (Unitless)**	**CH_4 (Unitless)**	**N_2O Emissions (Unitless)**	
Boiler Unit 1	4,834,050	40	30	1	21	310	4,844,241
Boiler Unit 2	3,751,800	31	23	1	21	310	3,759,709
Boiler Unit 3	3,751,800	31	23	1	21	310	3,759,709

Notes:
1) Emission Factors for Coal Combustion are from AP-42, Chapter 1.1, Tables 1.1-19 and 1.1-20, 9/98.
2) Emission Factors for Fuel Oil Combustion are from AP-42, Chapter 1.3, Tables 1.3-3, 1.3-8 and 1.3-12, 5/10.

Methodology:
1) PTE (TPY) = (throughput x emission factor) / 2,000lb per ton
2) CO_2e = sum(pollutant emissions x global warming potential)

Appendix A: Emission Calculations
Coal Dumping and Handling

Company Name: NIPSCO - R.M Schahfer Generating Station
Address: 2723 East 1500 North, Wheatfield, IN 46392
Renewal No: 073-29983-00008
Reviewer: Josiah Balogun
Date: 2-Aug-2012

1. Coal Dumping
Emissions are generated when the coal is dumped from trucks.

EF (lb/ton) = k * (0.0032) * (U/5)^1.3 / (M/2)^1.4
(Emission factor equation is from AP 42, Chapter 13.2.4.)

where: k value for:

PM	PM10
1	0.35

U value =	10	mph
M value =	4.5	%
Material Throughput =	26,280,000	tons/yr

PM EF =	2.53E-03	lb/ton
PM10 EF =	8.86E-04	lb/ton

PTE of PM (tons/year) = EF (lb/ton) * Maximum Throughput (tons/yr) * 1ton/2000 lbs **PTE of PM (tons/year) = 33.27**
PTE of PM10 (tons/year) = EF (lb/ton) * Maximum Throughput (tons/yr) * 1ton/2000 lbs **PTE of PM10 (tons/year) = 11.64**

2. Coal Conveying

Unit Description	Number of Conveyor Units	Max. Capacity (tons/hr/unit)	PM Emission Factor* (lbs/ton)	PM10 Emission Factor* (lbs/ton)	PTE of PM (tons/yr)	PTE of PM10 (tons/yr)
Conveyors	2	3,000.0	1.4E-04	4.6E-05	3.679	1.209

* Emission factors are from AP-42, Table 11.19.2-2 (08/04).
Since the coal received at this facility has high moisture content (6.9%), the controlled emission factors in AP-42, Table 11.19.2-2 are used in the PTE calculations.

Methodology
PTE of PM/PM10 (tons/yr) = Number of Conveyor Units x Max. Capacity (tons/hr/unit) x Emission Factor (lbs/ton) x 8760 hrs/yr x 1 ton/2000 lbs

Limestone Material Handling Systems
Unit 14 and Unit 15 FGD Systems
Drop Point Calculation

Parameter		Value	Units	Source / Basis
Limestone Throughput Annual	=	301,000	tons/year	Engineering Estimate
Limestone Throughput Hourly	=	100	tons/hour	Ton/hour calculated based on 32 trucks a day 25 tons/truck and one unloading shift 8 hr/day
Number of Drop Points	=	1	Number	Limestone unloading from truck to Silo
Moisture Content (M)	=	1.00	%	Conservative estimate
Annual Mean Wind speed (U)	=	10.00	mph	From RMS Calculations for Material Handling Emissions
PM Particle size multiplier (kP)	=	0.740	dimensionl	Ref. 1
PM10 Particle size multiplier (kP)	=	0.350	dimensionl	Ref. 1
PM2.5 Particle size multiplier (kP)	=	0.053	dimensionl	Ref. 1
PM Emission Factor	=	0.01539	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM10 Emission Factor	=	0.00728	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM2.5 Emission Factor	=	0.00110	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
Control Efficiency	=	99.90%	Use of Bag Filter - Pneumatic Unloading and Conveyance Integral to the Process	

PTE Calculation Results

	PTE, Controlled					
	lb/hr			tpy		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
Limestone unloading	0.0015	0.0007	0.0001	0.0023	0.0011	0.0002

	PTE, Uncontrolled					
	lb/hr			tpy		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
Limestone unloading	1.54	0.73	0.11	2.32	1.10	0.17

1. EPA AP-42 Chapter 13.2.4; 11/2006.

Gypsum Material Handling Systems
Unit 14 and Unit 15 FGD Systems
Drop Point Calculation

Parameter		Value	Units	Source / Basis
Gypsum Throughput Annual	=	551,000	tons/year	Engineering Estimate
Gypsum Throughput Hourly	=	172	tons/hour	Ton/hour calculated based on 55 trucks a day 25 tons/truck and one unloading shift 8 hr/day
Percent Gypsum Off-spec	=	2.5%	%	Site-specific experience based on amount of gypsum deposited on strategic pile
Gypsum Throughput Annual to GP	=	507,000	tons/year	
Reclaim Dewatered Gypsum to GP Conveyor	=	6	Number	Six drop points[a]
Reclaim Dewatered Gypsum to Strategic Pile	=	5	Number	Two drop points[b]
Strategic Pile to Ship Out	=	1	Number	One drop point[c]
Moisture Content (M)	=	4.80	%	Conservative estimate
Annual Mean Wind speed (U)	=	10.00	mph	From RMS Calculations for Material Handling Emissions
PM Particle size multiplier (kP)	=	0.740	dimensionl	Ref. 1
PM10 Particle size multiplier (kP)	=	0.350	dimensionl	Ref. 1
PM2.5 Particle size multiplier (kP)	=	0.053	dimensionl	Ref. 1
PM Emission Factor	=	0.00171	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM10 Emission Factor	=	0.00081	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM2.5 Emission Factor	=	0.00012	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1

PTE Calculation Results

PTE, Controlled

	lb/hr			tpy		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
Reclaim Dewatered Gypsum to GP Conveyor	1.77	0.83	0.13	2.60	1.23	0.19
Reclaim Dewatered Gypsum to Strategic Pile	1.47	0.70	0.11	0.19	0.09	0.01
Strategic Pile to Ship Out	0.29	0.14	0.02	0.04	0.02	0.00

PTE, Uncontrolled

	lb/hr			tpy		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
Reclaim Dewatered Gypsum to GP Conveyor	1.77	0.83	0.13	2.60	1.23	0.19
Reclaim Dewatered Gypsum to Strategic Pile	1.47	0.70	0.11	0.19	0.09	0.01
Strategic Pile to Ship Out	0.29	0.14	0.02	0.04	0.02	0.00

References:
1. EPA AP-42 Chapter 13.2.4; 11/2006.

Notes:
[a] Gypsum Handling - Belt Filter -> New Short Conveyor -> New Long Conveyor -> Units 17 or 18 Existing Conveyors -> Radial Stacker Existing -> Short Belt Feeder Existing -> Wall Board Plant Conveyor
[b] Offspec Gypsum Handling - Belt Filter -> New Short Conveyor -> New Long Conveyor -> Units 17 or 18 Existing Conveyors -> Radial Stacker Existing -> Truck -> Strategic Pile
[c] Offspec Gypsum from strategic pile reclaim to Truck

Gypsum Material Handling Systems
Unit 14 and Unit 15 FGD Systems
Gypsum Storage Pile Calculation

Parameter		Value	Units	Source / Basis
Gypsum Storage in Pile	=	48,400	tons	From Gypsum sheet; Capacity as 1.1 times the annual throughput
Void Ratio	=	0.1		assumed value 10% void
Gypsum Density	=	55	lb/cu ft	http://www.ehow.com/list_6038366_physical-properties-gypsum-powder.html
Volume of Pile Vp	=	1,955,556	cu ft	=B5*2000/B4/(1-B6)
Angle of repose	=	35	degrees	http://www.powderandbulk.com/resources/bulk_density/material_bulk_density_chart_c.htm
Radius of pile	=	138.68	ft	=((3*B8)/(PI()*TAN(RADIANS(B9))))^(1/3)
Height of pile	=	97.10	ft	=B10*TAN(RADIANS(B9))
Storage Pile Area	=	120,834	ft2	=PI()*B10^2 * 2 piles
Storage Pile Area	=	2.77	acre	=B12/43,560
Annual Pile Days	=	365	days/yr	
Gypsum Silt Content (s)	=	3.9	wt. %	AP-42; Table 13.2.4-1, Various Limestone Products; 11/06
Threshold Wind Speed (f)	=	28	% of time	% of time that wind speed exceeds 12 mph at mean pile height
	=			Data from South Bend/Michiana, Sta. 14848, 1988-92.
Days with > 0.01" of precipitation (p)	=	120	days/yr	AP-42; Figure 13.2.2-1; 11/06 for Wheatfield Indiana
PM Particle Size Multiplier	=	1.0		Air Pollution Engineering Manual; p 136; AWMA; 1992
PM-10 Particle Size Multiplier	=	0.5		Air Pollution Engineering Manual; p 136; AWMA; 1992
PM-2.5 Particle Size Multiplier	=	0.2		Air Pollution Engineering Manual; p 136; AWMA; 1992
PM Emission Factor	=	8.6	lb/day/acre	Air Pollution Engineering Manual; p 136; Eqn. 5; AWMA; 1992
PM-10 Emission Factor	=	4.3	lb/day/acre	Air Pollution Engineering Manual; p 136; Eqn. 5; AWMA; 1992
PM-2.5 Emission Factor	=	1.7	lb/day/acre	Air Pollution Engineering Manual; p 136; Eqn. 5; AWMA; 1992
Hourly PM Emissions	=	23.86	lb/hr	=B22*B13; hourly emissions assumed equal to daily
Hourly PM-10 Emissions	=	11.93	lb/hr	=B23*B13; hourly emissions assumed equal to daily
Hourly PM-2.5 Emissions	=	4.77	lb/hr	=B24*B13; hourly emissions assumed equal to daily
Annual PM Emissions	=	4.35	tpy	=B13*B14*B22/2000
Annual PM-10 Emissions	=	2.18	tpy	=B13*B14*B23/2000
Annual PM-2.5 Emissions	=	0.87	tpy	=B13*B14*B24/2000

Limestone Trucks on Paved Roads
Unit 14 and Unit 15 FGD Systems
Paved Haul Road Calculation

Parameter		Value	Units	Basis
Limestone by Truck	=	301,000	tons/year	Engineering Estimate
Truck Travel Distance (Round Trip)	=	0.4	miles	Paved road length from gate to silo - 1000 feet estimated
Empty Limestone Truck Weight	=	15	tons	Use 30,000 lb
Loaded Limestone Truck Weight	=	40	tons	Use 25 Tons/Truck
Mean Vehicle Weight (W)	=	28	tons	=(C9+C10)/2
Annual Trips	=	12,040	trips/yr	=C6/(C10-C9)
Truck miles per year	=	4,561	VMT/yr	=C12*C8
Paved Road Silt Loading (sL)	=	9.7	g/m2	AP-42; Table 13.2.1-3; Irons and Steel Production
Days with > 0.01" of precipitation (p)	=	120.0	days	AP-42; Figure 13.2.1-2
PM particle size factor (k)	=	0.011	lb/VMT	AP-42; Table 13.2.1-1
PM10 particle size factor (k)	=	0.0022	lb/VMT	AP-42; Table 13.2.1-1
PM2.5 particle size factor (k)	=	0.00054	lb/VMT	AP-42; Table 13.2.1-1
Uncontrolled PM Emissions Factor	=	2.35	lb/VMT	AP-42, Ch. 13.2.1, Eqn. 2
Uncontrolled PM10 Emissions Factor	=	0.47	lb/VMT	AP-42, Ch. 13.2.1, Eqn. 2
Uncontrolled PM2.5 Emissions Factor	=	0.12	lb/VMT	AP-42, Ch. 13.2.1, Eqn. 2
Uncontrolled Annual PM Emissions	=	5.35	tons/yr	=C19*$C$13/2000
Uncontrolled Annual PM10 Emissions	=	1.07	tons/yr	=C20*$C$13/2000
Uncontrolled Annual PM2.5 Emissions	=	0.26	tons/yr	=C21*$C$13/2000
Control Measure Efficiency	=	0%	%	Assumed no control
Controlled Annual PM Emissions	=	5.35	tons/yr	=C22*(1-$C$25)
Controlled Annual PM10 Emissions	=	1.07	tons/yr	=C23*(1-$C$25)
Controlled Annual PM2.5 Emissions	=	0.26	tons/yr	=C24*(1-$C$25)

Notes:
1. The revised EPA AP-42 Chapter 13.2.1 (Jan 2011) is used for this calculation:
http://www.epa.gov/ttn/chief/ap42/ch13/index.html
2. For the purpose of this calculation, limestone truck roads are considered a new emissions unit.

Gypsum Trucks on Unpaved Roads
Unit 14 and Unit 15 FGD Systems
Unpaved Haul Road Calculation

Parameter		Value	Units	Basis
Gypsum by Trucks	=	44,000	tons/year	Difference between amount of Gypsum produced and sent to GP
Truck Travel Distance (Round Trip)	=	1.6	miles	Road distance from Gypsum dewatering to storage pile 0.8 miles
Empty Gypsum Truck Weight	=	15	tons	Use 30,000 lb
Loaded Gypsum Truck Weight	=	40	tons	Use 25 Tons/Truck
Mean Vehicle Weight (W)	=	28	tons	=(C9+C10)/2
Annual Trips	=	1,760	trips/yr	=C6/(C10-C9)
Truck miles per year	=	2,816	VMT/yr	=C12*C8
Silt Content (s)	=	4.8	%	AP-42 Table 13.2.2-1 Sand and Gravel Processing; mean value
Days with > 0.01" of precipitation (p)	=	120.0	days	AP-42; Figure 13.2.2-1; Draft
PM particle size factor (k)	=	4.9	lb/VMT	AP-42; Table 13.2.2-2; Draft
PM10 particle size factor (k)	=	1.5	lb/VMT	AP-42; Table 13.2.2-2; Draft
PM2.5 particle size factor (k)	=	0.15	lb/VMT	AP-42; Table 13.2.2-2; Draft
Uncontrolled PM Emissions Factor	=	4.69	lb/VMT	AP-42, Ch. 13.2.1, Eqn. 1; Draft
Uncontrolled PM10 Emissions Factor	=	1.20	lb/VMT	AP-42, Ch. 13.2.1, Eqn. 1; Draft
Uncontrolled PM2.5 Emissions Factor	=	0.12	lb/VMT	AP-42, Ch. 13.2.1, Eqn. 1; Draft
Uncontrolled Annual PM Emissions	=	6.61	tons/yr	=C19*$C$13/2000
Uncontrolled Annual PM10 Emissions	=	1.68	tons/yr	=C20*$C$13/2000
Uncontrolled Annual PM2.5 Emissions	=	0.17	tons/yr	=C21*$C$13/2000
Control Measure Efficiency	=	0%	%	Assumed no control
Controlled Annual PM Emissions	=	6.61	tons/yr	=C22*(1-$C$25)
Controlled Annual PM10 Emissions	=	1.68	tons/yr	=C23*(1-$C$25)
Controlled Annual PM2.5 Emissions	=	0.17	tons/yr	=C24*(1-$C$25)

Notes:
1. For the purpose of this calculation, gypsum truck roads are considered a new emissions unit.

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Company Name: NIPSCO - R.M Schahfer Generating Station
Address City IN Zip: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Reviewer: Josiah Balogun
Date: 2-Aug-2012

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	288.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	144,000
Sulfur Content (S) of Fuel (% by weight)	0.500

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	7.00E-04	4.01E-04	4.01E-04	4.05E-03 *(.00809S)*	2.40E-02 **see below	7.05E-04	5.50E-03
Potential Emission in tons/yr	0.05	0.03	0.03	0.29	1.73	0.05	0.40

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).
**NOx emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	3.91E-04	1.42E-04	9.73E-05	3.98E-05	1.27E-05	3.97E-06	1.07E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**7.93E-04**

Green House Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.16E+00	6.35E-05	9.30E-06
Potential Emission in tons/yr	8.35E+01	4.57E-03	6.70E-04

Summed Potential Emissions in tons/yr	**8.35E+01**
CO2e Total in tons/yr	**8.38E+01**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #14

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal	Potential Throughput tons/year
4650	11,500	1,771,043

Weight % Sulfur in Fuel	Weight % Ash in Fuel
0.500	2.1

Limited	Pollutant						
	PM*	PM10*	PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.1 (2A)	1 (0.26A)	1 (0.26A)	6.0 *(38S)*	33.0	0.11	0.5
Potential Emission in tons/yr	88.6	483.5	483.5	5313.1	29222.2	97.4	442.8

Emission Factors are from AP-42, Table 1.1-3, 1.1-4 and 1.1-5 (09/98) for Cyclone bituminous
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Assume the Heating value of the coal used at this plant is 23.868 MMBtu/ton

Methodology

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	5133	1	0
Potential Emission, ton/yr	4,545,714	535	78
Summed Potential Emissions, tons/yr	4,546,327		
l Warming Potential (100 Year)	1	21	310
CO2e Total in tons/yr	4,581,097		

Methodology

Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton

Emission Factors from Tables C-1 and 2 of 40 CFR Part 98 Subpart C and have been converted from kg/MMBtu to lb/ton.

Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #15

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
5100	11111	2.01E+06

	Weight %		Weight %
Sulfur =	2.3	Ash =	5.40

Limited	Pollutant (tons per year)					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/ton	54.0	12.42	6.0	11.0	0.06	1.63
	(10A)	*(2.3A)*	*(38S)*			
Potential Emission in tons/yr	54,282	12,485	6,031	11,057	60	1,639

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #17

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %
Sulfur =	2.3

	Weight %
Ash =	5.40

Limited	Pollutant (tons per year)					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7	12.42	13.8	12.0	0.06	6.00
	(10A)	*(2.3A)*	*(38S)*			
Potential Emission in tons/yr	524	9,711	10,790	9,383	47	4,691

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %
Sulfur =	2.3

	Weight %
Ash =	5.40

Limited	Pollutant (tons per year)					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7	12.42	13.8	12.0	0.06	6.00
	(10A)	*(2.3A)*	*(38S)*			
Potential Emission in tons/yr	524	9,711	10,790	9,383	47	4,691

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #14

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 29-Nov-2012

Heat Input Capacity MMBtu/hr	Heat Content of Coal Btu/lb of Coal	Potential Throughput tons/year
4650	~~11500~~ **9216**	~~1771043~~ **2209961**

Weight % Sulfur in Fuel	Weight % Ash in Fuel
~~0.5~~ **0.39**	~~2.1~~ **5.2**

Limited	Pollutant						
	PM*	PM10/PM2.5*	PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	~~0.1~~ **1.8** (2A)	1 (0.26A)	1 (0.26A)	~~6~~ **14.8** *(38S)*	~~33~~ **2.2**	0.11	0.5
Potential Emission in tons/yr	~~88.6~~ **2036.7**	~~483.5~~ **1493.9**	~~483.5~~ **1493.9**	~~5313.1~~ **16375.8**	~~29222.2~~ **2444**	~~97.4~~ **121.5**	~~442.8~~ **522.5**

Emission Factors are from AP-42, Table 1.1-3, 1.1-4 and 1.1-5 (09/98) for Cyclone bituminous

VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).

Assume the Heating value of the coal used at this plant is **18.43** ~~23.868~~ MMBtu/ton

Methodology

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton

Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #15

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
5100	~~11111~~ **8900**	~~2010000~~ **2510000**

	Weight %
Sulfur =	~~2.3~~ 0.2

	Weight %
Ash =	~~5.4~~ 5.0

Limited	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	~~54~~ **1.8** *(10A)*	~~12.42~~ **11.5** *(2.3A)*	~~6~~ **21.4** *(38S)*	~~11~~ **3.2**	0.06	1.63
Potential Emission in tons/yr	~~54282~~ **2234**	~~12485~~ **14432**	~~6031~~ **26806**	~~11057~~ **4021**	~~60~~ **75**	~~1639~~ **2046**

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.

Heat content (~~11,111~~ **8900** Btu/lb) reported by source permittee as average value

VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)

Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton

Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #17

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %
Sulfur =	~~2.3~~ **3.2**

	Weight %
Ash =	~~5.4~~ **8.9**

Limited	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7 *(10A)*	~~12.42~~ **20.47** *(2.3A)*	~~13.8~~ **3.6** *(38S)*	~~12~~ **4.4**	0.06	6.00
Potential Emission in tons/yr	524	~~9711~~ **16006**	~~10790~~ **2852**	~~9383~~ **3475**	47	4,691

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %
Sulfur =	~~2.3~~ **3.2**

	Weight %
Ash =	~~5.4~~ **8.9**

Limited	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7 *(10A)*	~~12.47~~ **20.47** *(2.3A)*	~~13.8~~ **3.6** *(38S)*	~~12~~ **4.4**	0.06	6.00
Potential Emission in tons/yr	524	~~9711~~ **16006**	~~10790~~ **2852**	~~9383~~ **3475**	47	4,691

Methodology

The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A to the Technical Support Document
Potential to Emit - Combustion Turbine 16A

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Heat Input Capacity (for NG)
MMBtu/hr

1450

	Pollutant					
	PM*	PM10/2.5*	SO_2	NOx	VOC	CO
Emission Factor in lbs/MMBtu	6.60E-03	6.60E-03	3.40E-03 S=0.0036	0.32	2.10E-03	0.082
Unlimited PTE (tons/yr)	**41.92**	**41.92**	**21.59**	**2,032**	**13.34**	**520.78**

*PM and PM10 emission factors are condensable and filterable PM combined. Assume PM10/2.5 emissions equal PM emissions.
Emission Factors from AP-42, Chapter 3.1, Tables 3.1-1 and 3.1-2: Emission Factors for Stationary Gas Turbines (04/00).

Methodology

Unlimited PTE (tons/yr) = Max. Input Capcity (MMBtu/hr) x Emission Factor (lbs/MMBtu) x 8760 hr/yr x 1 ton/2000 lbs

Appendix A to the Technical Support Document
Potential to Emit HAP - Combustion Turbine 16A

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Heat Input Capacity (for NG)
MMBtu/hr

1450

	Pollutant					
	Formaldehyde	Toluene	Xylene	Acetaldehyde	Ethylbenzene	Total
Emission Factor in lbs/MMBtu	7.10E-04	1.30E-04	6.40E-05	4.00E-05	3.20E-05	
PTE (tons/yr)	**4.51**	**0.83**	**0.41**	**0.25**	**0.20**	**6.20**

Note: Emission factors are from AP-42, Table 3.1-3 for NG fired gas turbines (AP-42, 04/00).

Methodology

PTE (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lbs/MMBtu) x 8760 hr/yr x 1 ton/2000 lbs

Appendix A to the Technical Support Document
Greenhouse Gas Emissions - Combustion Turbine 16A

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Turbine PTE - Unit 16A

Maximum Heat Input	1450	MMBtu/hr
	12,702,000	MMBtu/year

Pollutant	CO2	CH4	N2O	Total
Emission Factor (Kg/MMBtu)	53.02	1.00E-03	1.00E-04	------
PTE (TPY)	740,806	13.97	1.40	740,821
PTE (TPY CO2e)	740,806	293	434	741,533

Methodology:

1) PTE (TPY) = Emission Factor (Kg/MMBtu) * 2.2 lb/Kg * Fuel Usage (MMBtu/yr) * 1 ton/2,000 lb
2) PTE (TPY CO2e) = PTE (TPY) * Global Warming Potential (Unitless); Where : CO2 = 1, CH4 = 21 and N2O = 310
3) Emission Factors are from 40 CFR 98, Subpart C, Tables C-1 and C-2, December 2010.
4) Natural Gas Limited Heat Input (MMBtu/yr) = 1,294 MMCF/yr * 1,020 MMBtu/MMCF.

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Appendix A to the Technical Support Document
Potential to Emit - Combustion Turbine 16 B

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Heat Input Capacity (for NG)
MMBtu/hr

1450

	Pollutant					
	PM*	PM10/2.5*	SO_2	NOx	VOC	CO
Emission Factor in lbs/MMBtu	6.60E-03	6.60E-03	3.40E-03 S=0.0036	0.32	2.10E-03	0.082
Unlimited PTE (tons/yr)	**41.92**	**41.92**	**21.59**	**2,032**	**13.34**	**520.78**

*PM and PM10 emission factors are condensable and filterable PM combined. Assume PM10/2.5 emissions equal PM emissions.
Emission Factors from AP-42, Chapter 3.1, Tables 3.1-1 and 3.1-2: Emission Factors for Stationary Gas Turbines (04/00).

Methodology

Unlimited PTE (tons/yr) = Max. Input Capcity (MMBtu/hr) x Emission Factor (lbs/MMBtu) x 8760 hr/yr x 1 ton/2000 lbs

Appendix A to the Technical Support Document
Potential to Emit HAP - Combustion Turbine 16B

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Heat Input Capacity (for NG)
MMBtu/hr

1450

	Pollutant					
	Formaldehyde	Toluene	Xylene	Acetaldehyde	Ethylbenzene	Total
Emission Factor in lbs/MMBtu	7.10E-04	1.30E-04	6.40E-05	4.00E-05	3.20E-05	
PTE (tons/yr)	**4.51**	**0.83**	**0.41**	**0.25**	**0.20**	**6.20**

Note: Emission factors are from AP-42, Table 3.1-3 for NG fired gas turbines (AP-42, 04/00).

Methodology

PTE (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lbs/MMBtu) x 8760 hr/yr x 1 ton/2000 lbs

Appendix A to the Technical Support Document
Greenhouse Gas Emissions - Combustion Turbine 16B

Source Name: NIPSCO - R.M Schahfer Generating Station
Source Location: 2723 East 1500 North, Wheatfield, IN 46392
Permit Number: 073-29983-00008
Permit Reviewer: Josiah Balogun
Date: 2-Aug-2012

Turbine PTE

Maximum Heat Input	1450	MMBtu/hr
	12,702,000	MMBtu/year

Pollutant	CO2	CH4	N2O	Total
Emission Factor (Kg/MMBtu)	53.02	1.00E-03	1.00E-04	------
PTE (TPY)	740,806	13.97	1.40	740,821
PTE (TPY CO2e)	740,806	293	434	741,533

Methodology:

1) PTE (TPY) = Emission Factor (Kg/MMBtu) * 2.2 lb/Kg * Fuel Usage (MMBtu/yr) * 1 ton/2,000 lb
2) PTE (TPY CO2e) = PTE (TPY) * Global Warming Potential (Unitless); Where : CO2 = 1, CH4 = 21 and N2O = 310
3) Emission Factors are from 40 CFR 98, Subpart C, Tables C-1 and C-2, December 2010.
4) Natural Gas Limited Heat Input (MMBtu/yr) = 1,294 MMCF/yr * 1,020 MMBtu/MMCF.

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Compliance Assurance Monitoring ("CAM") Proposal

Prepared for

Northern Indiana Public Services Company (NIPSCO)

R.M. Schahfer Generating Station

Wheatfield, Indiana

Prepared by

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304-A West Millbrook Road

Raleigh, NC 27609

November 2010

General Background

This proposed monitoring plan was designed to meet the requirements of 40 CFR 64 "Compliance Assurance Monitoring" (CAM rule) for particulate matter emissions (PM) for Units 14, 15, 17, and 18, and for sulfur dioxide (SO_2) emissions for Units 17 and 18.

EMISSIONS UNIT 14

Emissions Unit Description

Source:	Northern Indiana Public Service Company (NIPSCO), R. M. Schahfer Generating Station, Wheatfield, IN
Identification:	Emission Unit ID: Unit 14
Description:	Cyclone type coal-fired boiler (Babcock and Wilcox) with a design heat input of 4,650 MMBtu/hour
Pollutant:	Particulate matter (PM)

Applicable Regulations, Emission Limit

Regulation:	326 IAC 6-2 "Particulate Emissions Limitations for Sources of Indirect Heating"
Emission Limit:	0.1 pounds of PM per million Btu heat input (per 326 IAC 6-2-3)

Monitoring Requirements

None specified in IDEM regulations in 326 IAC 6-2. The current Part 70 Permit T073-6792-00008 requires following:

(a) D.1(a) – Requirement to Install Continuous Opacity Monitor

(b) D.1.2 – Startup, Shutdown, and Other Opacity Limits

(c) D.1.5 – Biennial Stack Testing

(d) D.1.9 – Transformer-Rectifier (T-R) Sets Monitoring

(e) D.1.10 – Opacity Readings (Trigger)

(f) D.1.12(a) – Recordkeeping Requirements

Control Technology Description

Unit 14 is equipped with a PM control device comprising a cold side Electrostatic

Precipitator (ESP). Exhaust from Unit 14 is routed to Stack 14.

Monitoring Approach Description

Type of Emissions Unit

The NIPSCO R. M. Schahfer Generating Station is a major source currently operating under Part 70 Permit T073-6792-00008. Boiler Unit 14 is equipped with a PM control device (ESP), and the uncontrolled potential to emit PM from this boiler is greater than 100 tons per year (100% of the amount for a source to be classified as major source). The control device is used to achieve compliance with 326 IAC 6-2. Therefore, in accordance with 40 CFR §64.2, the pollutant-specific emissions unit (PM emissions from Unit 14) is subject to the CAM rule. Also the potential to emit for Unit 14 determined considering the effect of air pollution control equipment is greater than 100% of the major source threshold. Therefore, in accordance with the requirements of 40 CFR §64.3(b)(4)(ii), Unit 14 is considered a 'large pollutant-specific emissions unit,' and the monitoring data collection frequency shall be at a minimum 'four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging period.'

Indicator(s) Monitored

40 CFR §64.4(a)(1) requires NIPSCO to identify indicator(s) to be monitored satisfying the requirements of 40 CFR §64.3(a)(1)-(2). The general monitoring criteria prescribed in 40 CFR §64.3(a)(1) are as follows.

> *The owner or operator shall design the monitoring to obtain data for one or more indicators of emission control performance for the control device, any associated capture system and, if necessary to satisfy paragraph (a)(2) of this section, processes at a pollutant-specific emissions unit. Indicators of performance may include ... process and control device parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities conducted by the owner or operator.*

NIPSCO has selected to monitor the opacity from Unit 14 ESP exhaust using the existing Continuous Opacity Monitoring System (COMS).

Indicator Range

40 CFR §64.4(a)(2) requires a CAM submittal to include the range or designated conditions of such indicators, or the process by which such indicator ranges or designated conditions will be established. NIPSCO is proposing to use the following parametric monitoring range for the PM control device associated with Unit 14:

- Unit 14 ESP: Average opacity in ESP exhaust above 30% for any three (3) consecutive six (6) minute averaging periods, except as otherwise allowed by D.1.2, will be considered as an excursion.

Performance Criteria

40 CFR §64.4(a)(3) requires the monitoring described above to meet the performance criteria at 40 CFR §64.3(b). Table 1 summarizes the CAM performance criteria requirements and details how the proposed monitoring satisfies these criteria.

Table 1. Summary of Monitoring Plan Performance Criteria

Regulatory Citation	Requirement	Proposal
§64.3(b)(1)	Data Representativeness	The COMS was installed at a representative location in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
§64.3(b)(2)	Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
§64.3(b)(3)	QA/QC Practices	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
§64.3(b)(4)	Monitoring Frequency	The opacity of the ESP exhaust is monitored continuously (every 10 seconds).
§64.3(b)(4)(i)	Data Averaging	The DAS retains all 6-minute opacity data. The 10-second opacity data are used to calculate 6-minute averages.

Rationale and Justification

In accordance with the requirements of 40 CFR §64.4(b), NIPSCO has documented the following justification for the proposed monitoring plan elements:

Justification for Use of Opacity

The CAM indicator selected is the opacity of the ESP exhaust for Unit 14 at the R. M. Schahfer Generating Station. Opacity was selected as the performance indicator because, as the opacity of the ESP emissions increases, it can be reasonably assumed that PM emissions increase.

Monitoring of opacity for the ESP controlled utility boilers is a common practice in industry and has been conducted for an extended period of time on the subject pollutant-specific emissions units. This indicator has also been included in the CAM plans for utility boiler permits recently issued by IDEM.

Justification for Indicator Ranges

40 CFR §64.4(c) requires the submittal of control device operating parameter data obtained during applicable compliance or performance tests. In addition, supplemental information related to indicator ranges for the performance of emissions control devices may be submitted based on engineering assessment and manufacturer's recommendations. Consistent with this requirement, selection of opacity indicator ranges for the control device was previously provided to IDEM and included in the Part 70 Permit T073-6792-00008.

Table 2 notes the proposed maximum opacity indicator threshold for Unit 14.

Table 2. Proposed Indicator Level based on Historical Emission Unit / Control Device Performance

Indicator	Unit 14
Opacity (three consecutive six minute averages)	>30% except for levels and periods as allowed by D.1.2

The opacity levels presented in Table 2 are consistent with those currently being

adhered to for the purpose of Part 70 Permit T073-6792-00008 periodic monitoring.

Operating Under CAM

40 CFR §64.7 addresses how CAM plans are to be implemented at the source. The table below summarizes these requirements and includes NIPSCO's proposed CAM implementation plan.

Table 3. Summary of CAM Implementation Plan

Regulatory Citation	Requirement	NIPSCO Implementation
§64.7(a)	Commencement of Operation	Consistent with 40 CFR §64.4(c) NIPSCO has proposed indicator ranges representing optimum performance of the emission control device. As this monitoring approach is consistent with periodic monitoring requirements contained in the current Part 70 permit for this source, NIPSCO proposes to continue to follow this monitoring approach. NIPSCO proposes to implement CAM on Unit 14 within 180 days after the issuance of the Part 70 permit renewal.
§64.7(b)	Proper Maintenance	NIPSCO will maintain the COMS equipment on the Unit 14 control device in accordance with manufacturer's recommendations. This will include, but not be limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
§64.7(c)	Continued Operation	Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), NIPSCO will collect data at all required intervals at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement.

Regulatory Citation	Requirement	NIPSCO Implementation
§64.7(d)	Responses to Excursions	Upon detecting an excursion or exceedance, NIPSCO will take reasonable response steps, which may include developing a corrective action plan, to restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response will include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

Quality Improvement Plan ("QIP")

40 CFR §64.8 provides that IDEM may require the development and implementation of a Quality Improvement Plan ("QIP"), if a determination is made that NIPSCO has not used acceptable procedures in response to excursions. At such time the IDEM makes this determination, NIPSCO will develop a QIP meeting the requirements of 40 CFR §64.8(b).

Reporting Requirements for CAM rule

40 CFR §64.9(a)(2) requires the Part 70 semi-annual report (40 CFR §70.6(a)(3)(iii)) to include the following:

1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken; and
2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with calibration checks, if applicable).

NIPSCO will ensure that the Part 70 semi-annual report includes the above required information with regard to excursions and any missing data. Consistent with 40 CFR §64.9(b), NIPSCO will maintain records of monitoring data and performance test data in accordance with the Part 70 recordkeeping requirements at 40 CFR §70.6(a)(3)(ii).

EMISSIONS UNIT 15

Emissions Unit Description

Source:	Northern Indiana Public Service Company (NIPSCO), R. M. Schahfer Generating Station, Wheatfield, IN
Identification:	Emission Unit ID: Unit 15
Description:	Dry bottom, pulverized coal-fired boiler with a design heat input of 5,100 MMBtu/hour
Pollutant:	Particulate matter (PM)

Applicable Regulations, Emission Limit

Regulation:	326 IAC 6-2 "Particulate Emissions Limitations for Sources of Indirect Heating", and NSPS 40 CFR 60 Subpart D "Standards of Performance for Fossil-Fuel-Fired Steam Generators for which Construction is Commenced after August 17, 1971"
Emission Limit:	0.1 pounds of PM per million Btu heat input (326 IAC 6-2-1(f), 40 CFR §60.42(a)(1))

Monitoring Requirements

Pursuant to 40 CFR §60.13(e) and 40 CFR §60.45(a) the current Part 70 Permit T073-6792-00008 requires the following:

(a) D.2.2(a) – Opacity Readings

(b) D.2.6(b) – Biennial Stack Testing

(c) D.2.9(a) – Requirement to Install Continuous Opacity Monitor (40 CFR §60.45(a))

(d) D.2.11 – Transformer-Rectifier (T-R) Sets Monitoring

(e) D.2.13(b) – Recordkeeping Requirements

Control Technology Description

Unit 15 is equipped with a PM control device comprising an Electrostatic Precipitator (ESP) with a flue gas conditioning (FGC) system. Exhaust from Unit 15 is routed to

Stack 15.

Monitoring Approach Description

Type of Emissions Unit

The NIPSCO R. M. Schahfer Generating Station is a major source currently operating under Part 70 Permit T 073-6792-00008. Boiler Unit 15 is equipped with a PM control device (ESP with FGC), and the uncontrolled potential to emit PM from this boiler is greater than 100 tons per year (100% of the amount for a source to be classified as major source). The control device is used to achieve compliance with 326 IAC 6-2. Therefore, in accordance with 40 CFR §64.2, the pollutant-specific emissions unit (PM emissions from Unit 15) is subject to the CAM rule. Also the potential to emit for Unit 15 determined considering the effect of air pollution control equipment is greater than 100% of the major source threshold. Therefore, in accordance with the requirements of 40 CFR §64.3(b)(4)(ii), Unit 15 is considered a 'large pollutant-specific emissions unit,' and the monitoring data collection frequency shall be at a minimum 'four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging period.'

Indicator(s) Monitored

40 CFR §64.4(a)(1) requires NIPSCO to identify indicator(s) to be monitored satisfying the requirements of 40 CFR §64.3(a)(1)-(2). The general monitoring criteria prescribed in 40 CFR §64.3(a)(1) are as follows.

> *The owner or operator shall design the monitoring to obtain data for one or more indicators of emission control performance for the control device, any associated capture system and, if necessary to satisfy paragraph (a)(2) of this section, processes at a pollutant-specific emissions unit. Indicators of performance may include ... process and control device parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities conducted by the owner or operator.*

NIPSCO has selected to monitor the opacity from Unit 15 ESP exhaust using the existing Continuous Opacity Monitoring System (COMS).

Indicator Range

40 CFR §64.4(a)(2) requires a CAM submittal to include the range or designated conditions of such indicators, or the process by which such indicator ranges or designated conditions will be established. NIPSCO is proposing to use the following parametric monitoring range for the PM control device associated with Unit 15:

- Unit 15 ESP: The opacity in the ESP exhaust shall not exceed 20% except for one six-minute period per hour of not more than 27% excluding periods of startup, shutdown, or malfunction.

Performance Criteria

40 CFR §64.4(a)(3) requires the monitoring described above to meet the performance criteria at40 CFR §64.3(b). Table 4 summarizes the CAM performance criteria requirements and details how the proposed monitoring satisfies these criteria.

Table 4. Summary of Monitoring Plan Performance Criteria

Regulatory Citation	Requirement	Proposal
§64.3(b)(1)	Data Representativeness	The COMS was installed at a representative location in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
§64.3(b)(2)	Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
§64.3(b)(3)	QA/QC Practices	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
§64.3(b)(4)	Monitoring Frequency	The opacity of the ESP exhaust is monitored continuously (every 10 seconds).
§64.3(b)(4)(i)	Data Averaging	The DAS retains all 6-minute opacity data. The 10-second opacity data are used to calculate 6-minute averages.

Rationale and Justification

In accordance with the requirements of 40 CFR §64.4(b), NIPSCO has documented the

following justification for the proposed monitoring plan elements:

Justification for Use of Opacity

The CAM indicator selected is the opacity of the ESP exhaust for Unit 15 at the R. M. Schahfer Generating Station. Opacity was selected as the performance indicator because, as the opacity of the ESP emissions increases, it can be reasonably assumed that PM emissions increase.

Monitoring of opacity for the ESP controlled utility boilers is a common practice in industry and has been conducted for an extended period of time on the subject pollutant-specific emissions units. This indicator has also been included in the CAM plans for utility boiler permits recently issued by IDEM.

Justification for Indicator Ranges

40 CFR §64.4(c) requires the submittal of control device operating parameter data obtained during applicable compliance or performance tests. In addition, supplemental information related to indicator ranges for the performance of emissions control devices may be submitted based on engineering assessment and manufacturer's recommendations. Consistent with this requirement, selection of opacity indicator ranges for the control device was previously provided to IDEM and included in the Part 70 Permit T073-6792-00008.

Table 5 notes the proposed maximum opacity indicator threshold for Unit 15.

Table 5. Proposed Indicator Level based on Historical Emission Unit / Control Device Performance

Indicator	Unit 15
Opacity (three consecutive six minute averages)	>20% except for one six-minute period per hour of not more than 27%

The opacity levels presented in Table 5 are consistent with those currently being adhered to for the purpose of Part 70 T073-6792-00008 periodic monitoring.

Operating Under CAM

40 CFR §64.7 addresses how CAM plans are to be implemented at the source. The

table below summarizes these requirements and includes NIPSCO's proposed CAM implementation plan.

Table 6. Summary of CAM Implementation Plan

Regulatory Citation	Requirement	NIPSCO Implementation
§64.7(a)	Commencement of Operation	Consistent with 40 CFR §64.4(c) NIPSCO has proposed indicator ranges representing optimum performance of the emission control device. As this monitoring approach is consistent with periodic monitoring requirements contained in the current Part 70 permit for this source, NIPSCO proposes to continue to follow this monitoring approach. NIPSCO proposes to implement CAM on Unit 15 within 180 days after the issuance of the Part 70 permit renewal.
§64.7(b)	Proper Maintenance	NIPSCO will maintain the COMS equipment on the Unit 15 control device in accordance with manufacturer's recommendations. This will include, but not be limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
§64.7(c)	Continued Operation	Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), NIPSCO will collect data at all required intervals at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement.

Regulatory Citation	Requirement	NIPSCO Implementation
§64.7(d)	Responses to Excursions	Upon detecting an excursion or exceedance, NIPSCO will take reasonable response steps, which may include developing a corrective action plan, to restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response will include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

Quality Improvement Plan ("QIP")

40 CFR §64.8 provides that IDEM may require the development and implementation of a Quality Improvement Plan ("QIP"), if a determination is made that NIPSCO has not used acceptable procedures in response to excursions. At such time the IDEM makes this determination, NIPSCO will develop a QIP meeting the requirements of 40 CFR §64.8(b).

Reporting Requirements for CAM rule

40 CFR §64.9(a)(2) requires the Part 70 semi-annual report (40 CFR §70.6(a)(3)(iii)) to include the following:

1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken; and
2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with calibration checks, if applicable).

NIPSCO will ensure that the Part 70 semi-annual report includes the above required information with regard to excursions and any missing data. Consistent with 40 CFR §64.9(b), NIPSCO will maintain records of monitoring data and performance test data in accordance with the Part 70 recordkeeping requirements at 40 CFR §70.6(a)(3)(ii).

EMISSIONS UNITS 17 & 18

Emissions Unit Description

Source:	Northern Indiana Public Service Company (NIPSCO), R. M. Schahfer Generating Station, Wheatfield, IN
Identification:	Emission Unit ID: Units 17 & 18
Description:	Each is a dry bottom, pulverized coal-fired boiler with a design heat input of 3,967 MMBtu/hour
Pollutant:	Particulate matter (PM)

Applicable Regulations, Emission Limit

Regulation:	326 IAC 2-2 "Prevention of Significant Deterioration", 326 IAC 6-2 "Particulate Emissions Limitations for Sources of Indirect Heating", and NSPS 40 CFR 60 Subpart Da "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September, 18, 1978"
Emission Limit:	0.03 pounds of PM per million Btu heat input (326 IAC 2-2-3, 326 IAC 6-2-1(g), 40 CFR §60.42a(a)(1))

Monitoring Requirements

Pursuant to 40 CFR §60.13(e) and 40 CFR §60.49a the current Part 70 Permit T 073-6792-00008 requires the following:

(a) D.3.2(a) – Opacity Readings

(b) D.3.5 – Biennial Stack Testing

(c) D.3.9(a) – Requirement to Install Continuous Opacity Monitor (40 CFR 60.49(a))

(d) D.3.11 – Transformer-Rectifier (T-R) Sets Monitoring

(e) D.3.13(a) – Recordkeeping Requirements

Control Technology Description

Units 17 and 18 are each equipped with PM control device, an Electrostatic Precipitator

(ESP) system. Exhaust from the Unit 17 ESP is routed to Stack 17, and exhaust from Unit 18 ESP is routed to Stack 18.

Monitoring Approach Description

Type of Emissions Unit

The NIPSCO R. M. Schahfer Generating Station is a major source currently operating under Part 70 Permit T073-6792-00008. Boiler Units 17 and 18 are each equipped with a PM control device (ESP), and the uncontrolled potential to emit PM from each boiler is greater than 100 tons per year (100% of the amount for a source to be classified as major source). The control device is used to achieve compliance with 326 IAC 6-2. Therefore, in accordance with 40 CFR §64.2, the pollutant-specific emissions unit (PM emissions from Unit 17 and 18) are each subject to the CAM rule. Also the potential to emit for Unit 17 or 18 determined considering the affect of air pollution control equipment is greater than 100% of the major source threshold. Therefore, in accordance with the requirements of 40 CFR §64.3(b)(4)(ii), Units 17 & 18 are each considered a 'large pollutant-specific emissions unit,' and the monitoring data collection frequency shall be at a minimum 'four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging period.'

Indicator(s) Monitored

40 CFR §64.4(a)(1) requires NIPSCO to identify indicator(s) to be monitored satisfying the requirements of 40 CFR §64.3(a)(1)-(2). The general monitoring criteria prescribed in 40 CFR §64.3(a)(1) are as follows.

> *The owner or operator shall design the monitoring to obtain data for one or more indicators of emission control performance for the control device, any associated capture system and, if necessary to satisfy paragraph (a)(2) of this section, processes at a pollutant-specific emissions unit. Indicators of performance may include ... process and control device parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities conducted by the owner or operator.*

NIPSCO has selected to monitor the opacity from Unit 17 and 18 ESP exhaust using the existing Continuous Opacity Monitoring System (COMS).

Indicator Range

40 CFR §64.4(a)(2) requires a CAM submittal to include the range or designated conditions of such indicators, or the process by which such indicator ranges or designated conditions will be established. NIPSCO is proposing to use the following parametric monitoring range for the PM control device associated with Units 17 and 18:

- Units 17 & 18 ESPs: The opacity in the ESP exhaust shall not exceed 20% except for one six-minute period per hour of not more than 27% excluding periods of startup, shutdown, or malfunction.

Performance Criteria

40 CFR §64.4(a)(3) requires the monitoring described above to meet the performance criteria at40 CFR §64.3(b). Table 7 summarizes the CAM performance criteria requirements and details how the proposed monitoring satisfies these criteria.

Table 7. Summary of Monitoring Plan Performance Criteria

Regulatory Citation	Requirement	Proposal
§64.3(b)(1)	Data Representativeness	The COMS was installed at a representative location in the ESP exhaust per 40 CFR 60, Appendix B, PS-1.
§64.3(b)(2)	Operational Status	Results of initial COMS performance evaluation conducted per PS-1.
§64.3(b)(3)	QA/QC Practices	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
§64.3(b)(4)	Monitoring Frequency	The opacity of the ESP exhaust is monitored continuously (every 10 seconds).
§64.3(b)(4)(i)	Data Averaging	The DAS retains all 6-minute opacity data. The 10-second opacity data are used to calculate 6-minute averages.

Rationale and Justification

In accordance with the requirements of 40 CFR §64.4(b), NIPSCO has documented the following justification for the proposed monitoring plan elements:

Justification for Use of Opacity

The CAM indicators selected is the opacity of the ESP exhaust for Unit 17 and 18 at the R. M. Schahfer Generating Station. Opacity was selected as the performance indicator because, as the opacity of the ESP emissions increases, it can be reasonably assumed that PM emissions increase.

Monitoring of opacity for the ESP controlled utility boilers is a common practice in industry and has been conducted for an extended period of time on the subject pollutant-specific emissions units. This indicator has also been included in the CAM plans for utility boiler permits recently issued by IDEM.

Justification for Indicator Ranges

40 CFR §64.4(c) requires the submittal of control device operating parameter data obtained during applicable compliance or performance tests. In addition, supplemental information related to indicator ranges for the performance of emissions control devices may be submitted based on engineering assessment and manufacturer's recommendations. Consistent with this requirement, selection of opacity indicator ranges for the control device was previously provided to IDEM and included in the Part 70 Permit T073-6792-00008.

Table 8 notes the proposed maximum opacity indicator threshold for Unit 17 and 18.

Table 8. Proposed Indicator Level based on Historical Emission Unit / Control Device Performance

Indicator	Unit 17 or 18
Opacity (three consecutive six minute averages)	>20% except for one six-minute period per hour of not more than 27%

The opacity levels presented in Table 8 are consistent with those currently being

adhered to for the purpose of Part 70 T073-6792-00008 periodic monitoring.

Operating Under CAM

40 CFR §64.7 addresses how CAM plans are to be implemented at the source. The table below summarizes these requirements and includes NIPSCO's proposed CAM implementation plan.

Table 9. Summary of CAM Implementation Plan

Regulatory Citation	Requirement	NIPSCO Implementation
§64.7(a)	Commencement of Operation	Consistent with 40 CFR §64.4(c) NIPSCO has proposed indicator ranges representing optimum performance of the emission control device. As this monitoring approach is consistent with periodic monitoring requirements contained in the current Part 70 permit for this source, NIPSCO proposes to continue to follow this monitoring approach. NIPSCO proposes to implement CAM on Units 17 and 18 within 180 days after the issuance of the Part 70 permit renewal.
§64.7(b)	Proper Maintenance	NIPSCO will maintain the COMS equipment on Units 17 and 18 control devices in accordance with manufacturer's recommendations. This will include, but not be limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
§64.7(c)	Continued Operation	Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), NIPSCO will collect data at all required intervals at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement.

Regulatory Citation	Requirement	NIPSCO Implementation
§64.7(d)	Responses to Excursions	Upon detecting an excursion or exceedance, NIPSCO will take reasonable response steps, which may include developing a corrective action plan, to restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response will include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

Quality Improvement Plan ("QIP")

40 CFR §64.8 provides that IDEM may require the development and implementation of a Quality Improvement Plan ("QIP"), if a determination is made that NIPSCO has not used acceptable procedures in response to excursions. At such time the IDEM makes this determination, NIPSCO will develop a QIP meeting the requirements of 40 CFR §64.8(b).

Reporting Requirements for CAM rule

40 CFR §64.9(a)(2) requires the Part 70 semi-annual report (40 CFR §70.6(a)(3)(iii)) to include the following:

1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken; and
2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with calibration checks, if applicable).

NIPSCO will ensure that the Part 70 semi-annual report includes the above required information with regard to excursions and any missing data. Consistent with 40 CFR §64.9(b), NIPSCO will maintain records of monitoring data and performance test data in accordance with the Part 70 recordkeeping requirements at 40 CFR §70.6(a)(3)(ii).

EMISSIONS UNITS 17 & 18

Emissions Unit Description

Source:	Northern Indiana Public Service Company (NIPSCO), R. M. Schahfer Generating Station, Wheatfield, IN
Identification:	Emission Unit ID: Units 17 & 18
Description:	Each is a dry bottom, pulverized coal-fired fired boiler with design heat input of 3,967 MMBtu/hour
Pollutant:	Sulfur Dioxide (SO_2)

Applicable Regulations, Emission Limit

Regulation:	326 IAC 2-2 "Prevention of Significant Deterioration", 326 IAC 7-1.1 "Sulfur Dioxide Emission Limitations", and NSPS 40 CFR 60 Subpart Da "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September, 18, 1978"
Emission Limit:	0.62 pounds of SO_2 per million Btu heat input (326 IAC 2-2, 40 CFR 326 IAC 7-1.1-2, 60.43a(a)(1) and (2))

Monitoring Requirements

Pursuant to 40 CFR §60.13(e) and 40 CFR §60.49a, the current Part 70 Permit T073-6792-00008 requires following:

(a) D.3.1(d) – SO_2 Readings

(b) D.3.9 (a) – Requirement to Install SO_2 Continuous Emission Monitoring System

(c) D.3.13(b) – Recordkeeping Requirements for SO_2 CEMs

CAM Applicability

The Part 70 Permit T 073-6792-00008 includes a 'continuous compliance determination method' for Unit 17 and 18 for the applicable SO_2 emission limitations by utilizing the

SO_2 CEMs.[1] Therefore, pursuant to 40 CFR §64.2(b)(1)(vi), the SO_2 emission limitations applicable to Unit 17 and Unit 18 are exempt from the requirement to submit a CAM plan.

[1] See 40 CFR § 64.1 Definitions - *Continuous compliance determination method* means a method, specified by the applicable standard or an applicable permit condition, which:
(1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and
(2) Provides data either in units of the standard or correlated directly with the compliance limit.

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF INDIANA

UNITED STATES OF AMERICA,	)	
and	)	
THE STATE OF INDIANA,	)	
Plaintiffs	)	
v.	)	**Civil Action No. _____**
NORTHERN INDIANA PUBLIC SERVICE CO.,	)	
Defendant.	)	

<u>CONSENT DECREE</u>

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Appendix A: Environmental Mitigation Projects

WHEREAS, Plaintiff, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA"), and Plaintiff, the State of Indiana, are filing with this Consent Decree a Complaint for injunctive relief and civil penalties pursuant to Sections 113(b)(2) and 167 of the Clean Air Act ("the Act"), 42 U.S.C. §§ 7413(b)(2) and 7477, and 326 Indiana Administrative Code sections 2-2 and 2-7, alleging that Defendant, Northern Indiana Public Service Co. ("NIPSCO"), has undertaken construction projects at major emitting facilities in violation of the Prevention of Significant Deterioration ("PSD") provisions of Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, in violation of Nonattainment New Source Review requirements, 42 U.S.C.§§ 7501-7515, in violation of the requirements of Title V of the Act, 42 U.S.C. §§ 7661-7661f and in violation of the federally enforceable Indiana State Implementation Plan ("SIP");

WHEREAS, EPA issued a Notice of Violation (the "NOV") to NIPSCO on September 29, 2004, pursuant to Section 113(a) of the Act, 42 U.S.C. § 7413(a), alleging violations at the Michigan City, Rollin M. Schahfer, and Bailly Generating Stations of:

(a) the PSD provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92,

(b) the Nonattainment New Source Review requirements in Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515,

(c) Subchapter V of the Act, 42 U.S.C. §§ 7661-7661f, and

(d) the federally enforceable Indiana SIP, including provisions implementing 40 C.F.R. § 52.21, and approved by EPA;

WHEREAS, EPA provided NIPSCO and the State of Indiana actual notice of the alleged violations and commencement of the action, in accordance with Section 113 of the Act, 42 U.S.C. § 7413;

WHEREAS, NIPSCO has been the owner and operator of the Michigan City, Rollin M. Schahfer, and Bailly Generating Stations from 1985 to the present;

WHEREAS, in the Complaint, Plaintiffs United States and the State of Indiana (collectively "Plaintiffs") allege, inter alia, that NIPSCO modified units and failed to obtain the necessary permits and install the controls necessary under the Act to reduce sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that such emissions can damage human health and the environment;

WHEREAS, Plaintiffs' Complaint states claims upon which, if proven, relief can be granted against NIPSCO under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, NIPSCO has denied and continues to deny the violations alleged in the Complaint and the NOV, and maintains that it has been and remains in compliance with the Act, federal implementing regulations and Indiana air regulations and statutes, including the Indiana SIP, and that it is not liable for civil penalties, injunctive or other relief;

WHEREAS, the Plaintiffs and the Defendant (collectively "the Parties," and each, individually, a Party) anticipate that the installation and operation of pollution control equipment pursuant to this Consent Decree will achieve significant reductions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and particulate matter ("PM") emissions and improve air quality; and

WHEREAS, the Parties have agreed, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arms' length; that this settlement is fair, reasonable, in the best interest of the Parties and the public, and is consistent with the goals of the Act and the Indiana SIP; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

WHEREAS, the Defendant has asserted that its Bailly Generating Station Units 7 and 8, Michigan City Generating Station Unit 12, and Schahfer Generating Station Unit 14, are cyclone-fired units, with cycling demand for electric generation and inherently high NOx baseline emissions, equipped with SCR (as hereinafter defined) systems with ammonia on demand ("AOD") systems.

NOW, THEREFORE, without any admission by the Defendant, and without adjudication of or admission with respect to the violations alleged in the Complaint or the NOV, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1) This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, and Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. §§ 1391(b) and (c).

2) Solely for the purposes of this Consent Decree and the underlying Complaint, Defendant waives all objections and defenses that it may have to the Court's jurisdiction over Defendant and to venue in this District. Defendant shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree and agrees that the Complaint states claims upon which, if such claims were proven, relief may be granted pursuant to Section 113 of the Act, 42 U.S.C. § 7413(b).

3) Solely for purposes of the Complaint filed by Plaintiffs in this matter and this Consent Decree, for purposes of entry and enforcement of this Consent Decree, Defendant waives any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than

Plaintiffs and Defendant. Except as provided in Section XXVIII (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice.

4) Notwithstanding the foregoing, should this Consent Decree not be entered by this Court, then the waivers and consents set forth in this Section I (Jurisdiction and Venue) shall be null and void and of no effect.

II. APPLICABILITY

5) Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the Plaintiffs, the United States, including EPA, and the State of Indiana, including the Indiana Department of Environmental Management, and upon NIPSCO, its successors and assigns, and its officers, employees and agents, solely in their capacities as such.

6) NIPSCO shall be responsible for providing a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other companies or organizations retained after entry of this Consent Decree to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, NIPSCO shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, NIPSCO shall not assert as a defense the failure of its officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless NIPSCO establishes that such failure resulted from a Force Majeure Event, as defined in Section XVI (Force Majeure) of this Consent Decree.

III. DEFINITIONS

7) A "365-Day Rolling Average Emission Rate" for a Cyclone-fired Unit, other than the Bailly Units, shall be expressed as lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of NOx emitted from the Cyclone-fired Unit during an Operating Day and the previous three hundred and sixty-four (364) Operating Days, with such emissions being determined from data derived from CEMS installed and operated at the Unit; second, sum the total heat input to the Cyclone-fired Unit in mmBTU during the Operating Day and the previous three hundred and sixty-four (364) Operating Days; and third, divide the total number of pounds of NOx emitted during those three hundred and sixty-five (365) Operating Days by the total heat input during those three hundred and sixty-five (365) Operating Days. For Bailly Units 7 and 8, which share common stacks, the "365-Day Rolling Average Emission Rate" shall be expressed as lb/mmBTU and calculated in accordance with the procedure enumerated above in this Paragraph for other Cyclone-fired Units, except that the total pounds of NOx emitted and the total heat input used to calculate the 365-Day Rolling Average Emission Rate shall be calculated by using the combined total pounds of NOx emitted from Bailly Units 7 and 8 and the combined total heat input to Bailly Units 7 and 8. A new 365-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. When a 365-Day Rolling Average Emission Rate includes Operating Days to which two different 365-Day Rolling Average Emission Rates apply, the less stringent 365-Day Rolling Average Emission Rate shall apply until such time as all Operating Days within the 365-day rolling average period fall within the more stringent specified 365-Day Rolling Average Emission Rate (e.g., if the specified 365-

Day Rolling Average Emission Rate for a Cyclone-fired Unit on December 31, 2009 is 0.140 lb/mmBTU and the specified 365-Day Rolling Average Emission Rate for that same Cyclone-fired Unit on December 31, 2010 becomes 0.120 lb/mmBTU, the less stringent December 31, 2009 specified rate would be the applicable 365-Day Rolling Average Emission Rate to determine on June 1, 2011 the Cyclone-fired Unit's compliance because the 365-Day Rolling Average Emission Rate determined on June 1, 2011 would include Operating Days prior to December 31, 2010). Each 365-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown and Malfunction within an Operating Day, except that emissions associated with a Malfunction that is determined to be a Force Majeure Event pursuant to Section XVI of this Consent Decree shall be excluded from the calculation of a 365-Day Rolling Average Emission Rate.

8) A "30-Day Rolling Average Emission Rate" for a Unit, other than the Bailly Units, shall be expressed as lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the Unit during an Operating Day and the previous twenty-nine (29) Operating Days, with such emissions being determined from data derived from CEMS installed and operated at the Unit; second, sum the total heat input to the Unit in mmBTU during the Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Operating Days by the total heat input during the thirty (30) Operating Days. For Bailly Units 7 and 8, which share common stacks, the "30-Day Rolling Average Emission Rate" shall be expressed as lb/mmBTU and calculated in accordance with the procedure enumerated

above in this Paragraph for other Units, except that the total pounds of NOx emitted and the total heat input used to calculate the 30-Day Rolling Average Emission Rate shall be calculated by using the combined total pounds of NOx emitted from Bailly Units 7 and 8 and the combined total heat input to Bailly Units 7 and 8. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. When a 30-Day Rolling Average Emission Rate includes Operating Days that fall within two different specified 30-Day Rolling Average Emission Rates, the less stringent 30-Day Rolling Average Emission Rate shall apply until such time as all Operating Days within the 30-day rolling average period fall within the more stringent specified 30-Day Rolling Average Emission Rate (e.g., if the specified 30-Day Rolling Average Emission Rate for a Unit on December 1, 2010 is 0.170 lb/mmBTU and the specified 30-Day Rolling Average Emission Rate for that same Unit on January 1, 2011 becomes 0.150 lb/mmBTU, the less stringent December 1, 2010 specified rate would be the applicable 30-Day Rolling Average Emission Rate to determine on January 15, 2011 the Unit's compliance because the 30-Day Rolling Average Emission Rate determined on January 15, 2011 would include Operating Days prior to January 1, 2011). Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown and Malfunction within an Operating Day, except that emissions associated with a Malfunction that is determined to be a Force Majeure Event pursuant to Section XVI of this Consent Decree shall be excluded from the calculation of a 30-Day Rolling Average Emission Rate.

9) A "30-Day Rolling Average Removal Efficiency" means the percent reduction in the emissions of a pollutant achieved by a Unit's pollution control device

over a 30-Operating Day period. This percentage shall be calculated by subtracting the Unit's outlet 30-Day Rolling Average Emission Rate from the Unit's inlet 30-Day Rolling Average Emission Rate, with such rates being determined from data derived from CEMS installed and operated at the Unit, dividing the result by the 30-Day Rolling Average Emission Rate from the Unit's inlet and then multiplying that result by 100. A new 30-Day Rolling Average Removal Efficiency shall be calculated for each new Operating Day. 30-Day Rolling Average Emission Rates used in the calculation of 30-Day Rolling Average Removal Efficiencies pursuant to this Paragraph shall include all emissions that occur during all periods of startup, shutdown and Malfunction within an Operating Day, except that emissions associated with a Malfunction that is determined to be a Force Majeure Event pursuant to Section XVI of this Consent Decree shall be excluded from the calculation of a 30-Day Rolling Average Emission Rate.

10) "Annual System Tonnage Limitation" means the limitation on the number of tons of the pollutant in question that may be emitted from the NIPSCO System during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of the pollutant emitted during periods of startup, shutdown and Malfunction.

11) "Boiler Island" means a Unit's: (a) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (b) combustion air system; (c) steam generating system (i.e., firebox, boiler tubes and walls); and (d) draft system (excluding the stack), as further described in "Interpretation of Reconstruction," John B. Rasnick, U.S. EPA (November 25, 1986), and the attachments thereto.

12) "Calendar Month" means all of the Operating Days in one calendar month period.

13) "Capital Expenditures" means all capital expenditures, as defined by Generally Accepted Accounting Principles ("GAAP"), as those principles exist at the Date of Entry of this Consent Decree, excluding the cost of installing or upgrading pollution control devices.

14) "CEMS" and "Continuous Emission Monitoring System" mean, for obligations involving NO_X and SO_2 under this Consent Decree, the devices defined in 40 C.F.R.§ 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

15) "Clean Air Act" and "the Act" mean the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and its implementing regulations.

16) "Consent Decree" and "Decree" mean this Consent Decree, including Appendix A which is hereto incorporated into this Consent Decree.

17) "Continuous Operation" and "Continuously Operate" mean, for obligations involving NOx, PM, and SO_2 under this Consent Decree, the operation of any specified NOx, PM or SO_2 control technology equipment at all times that the Unit it serves is in operation, except during a Malfunction of the control technology equipment, consistent with technological limitations, manufacturers' specifications, and good air pollution control practices for minimizing emissions (as defined in 40 C.F.R. § 60.11(d)).

18) "Cyclone-fired Unit" means those Units in the NIPSCO System that operate cyclone-fired boilers for electric generation and have inherently high NOx baseline emissions. The following Units in the NIPSCO System are considered Cyclone-fired Units: Bailly Unit 7 and Unit 8, Michigan City Unit 12, and Schahfer Unit 14.

19) "Date of Entry" means the date this Consent Decree is signed or otherwise approved in writing by the District Court Judge for the United States District Court for the Northern District of Indiana.

20) "Date of Lodging" means the date this Consent Decree is filed for lodging with the Clerk of the Court for the United States District Court for the Northern District of Indiana.

21) "Defendant" means the Northern Indiana Public Service Co. ("NIPSCO").

22) "Emission Rate" means the number of pounds of pollutant emitted per million British thermal units of heat input ("lb/mmBTU"), measured in accordance with this Consent Decree.

23) "EPA" means the United States Environmental Protection Agency.

24) "ESP" and "Electrostatic Precipitator" mean a device for removing particulate matter from combustion gases by imparting an electric charge to the particles and then attracting them to a metal plate or screen of opposite charge before the combustion gases are exhausted to the atmosphere.

25) "Flue Gas Desulfurization System" and "FGD" mean a pollution control device that employs flue gas desulfurization technology, including an absorber utilizing lime, fly ash, or limestone slurry, for the reduction of sulfur dioxide emissions.

26) "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum oil, and natural gas.

27) "Improved Unit" means, in the case of NO_X, a NIPSCO System Unit that has an SCR or is scheduled under this Consent Decree to be equipped with an SCR (or an equivalent NOx control technology approved pursuant to Paragraph 65) or in the case of

SO_2, a NIPSCO System Unit that has an FGD or is scheduled under this Consent Decree to be equipped with an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 80) in accordance with this Consent Decree. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for the other. The following Units are, in accordance with the preceding sentences, Improved Units for purposes of this Consent Decree: Bailly Units 7 and 8 (NO_X and SO_2); Michigan City Unit 12 (NO_X and SO_2); Schahfer Unit 14 (NO_X and SO_2); Schahfer Unit 15 (SO_2) and Schahfer Units 17 and 18 (SO_2). Schahfer Unit 15 can become an Improved Unit for NOx, if NIPSCO elects NOx Option 1 as described in Table 1 and Paragraph 60 of this Consent Decree. Schahfer Unit 15 can also become an Improved Unit for NOx if NIPSCO elects NOx Option 2 as described in Table 1 and Paragraph 60 and Schahfer Unit 15 becomes, at NIPSCO's discretion, subject to a federally enforceable 0.080 lb/mmBTU NO_X 30-Day Rolling Average Emission Rate, for which the rate and the requirement to Continuously Operate such SNCR is incorporated into a site-specific amendment to the SIP and modification to the Title V permit. Schahfer Units 17 and 18 can become an Improved Unit for NOx if either Unit is equipped with an SCR (or equivalent NO_X control technology approved pursuant to Paragraph 65) and has become subject to a federally enforceable 0.080 lb/mmBTU NO_X 30-Day Rolling Average Emission Rate, which rate, and the requirement to Continuously Operate such SCR, is incorporated into a site-specific amendment to the SIP and modification to the Title V permit.

28) "Indiana SIP" means the Indiana state implementation plan approved and enforceable by EPA under Section 110 of the Act.

29) “lb/mmBTU” means one pound of a pollutant per million British thermal units of heat input.

30) “Low Sulfur Coal” means coal that will achieve an uncontrolled SO_2 emission rate of less than 1.00 lb/mmBTU.

31) “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. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

32) “Monthly SO_2 Removal Efficiency” means the percent reduction in SO2 emissions achieved by the FGD at Bailly Units 7 and 8 during a Calendar Month. This percentage shall be calculated in accordance with the following procedure: (a) first, sum the total pounds of SO_2 emitted during a Calendar Month from the outlet at the Bailly main stack (CS001) and the Bailly bypass stack; (b) second, divide that sum by the sum of the total pounds of SO_2 during that same Calendar Month that enter the Bailly FGD (as measured at the inlet to the FGD) and are emitted from Bailly bypass stack; (c) third, subtract that result from 1.0 or 100 percent (*i.e.*, if the resulting number is 0.10, subtract 0.10 from 1.0); and, (d) fourth, multiply that result by 100. The pounds of SO_2 emitted from the Bailly main stack (CS001), inlet to the FGD, and bypass stack shall be determined from data derived from SO_2 CEMS installed and operated at Bailly. Emissions associated with a Malfunction that is determined to be a Force Majeure Event pursuant to Section XVI of this Consent Decree shall be excluded from the calculation of a Monthly SO_2 Removal Efficiency.

33) “MW” means a megawatt or one million watts.

34) "National Ambient Air Quality Standards" and "NAAQS" mean the national ambient air quality standards that are promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

35) "NIPSCO" means Northern Indiana Public Service Co.

36) "NIPSCO System" means the following coal-fired, electric steam-generating Units owned by NIPSCO and located in the State of Indiana, with estimated net demonstrated generating capacities for such Units listed in parentheses below:

a. the Bailly Electric Generation Station ("Bailly") in Porter County, IN, comprised of Unit 7 (160 MW) and Unit 8 (320 MW);

b. the Michigan City Generating Station ("Michigan City") in LaPorte County, IN, comprised of Unit 12 (469 MW);

c. the Rollin M. Schahfer Electric Generating Station ("Schahfer") in Jasper County, IN, comprised of Unit 14 (431 MW), Unit 15 (472 MW), Unit 17 (361 MW), and Unit 18 (361 MW); and

d. the Dean H. Mitchell Electric Generating Station ("Mitchell") in Lake County, IN, comprised of Unit 4 (110 MW), Unit 5 (125 MW), Unit 6 (126 MW), and Unit 11 (125 MW).

37) "Nonattainment New Source Review" and "Nonattainment NSR" mean the nonattainment area New Source Review ("NSR") program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515, and 40 C.F.R. Part 51, as well as any Nonattainment NSR provisions of the Indiana SIP.

38) "NO_X" means oxides of nitrogen.

39) "NO_X Allowance" means an authorization or credit to emit a specified amount of NO_X that is allocated or issued under an emissions trading or marketable permit program of any kind that has been established under the Clean Air Act or the Indiana SIP.

40) "Over- Fired Air" and "OFA" mean an in-furnace staged combustion control to reduce NO_X emissions.

41) "Operating Day" means any calendar day during which a Unit fires Fossil Fuel.

42) "Other Unit" means any Unit within the NIPSCO System that is not an Improved Unit for the pollutant in question. A Unit may be an Improved Unit for NO_X and an Other Unit for SO_2, and vice versa.

43) "Ownership Interest" means part or all of NIPSCO's legal or equitable ownership interest in the NIPSCO System Units.

44) "Parties" means the United States, including the EPA and the United States Department of Justice, the State of Indiana, including the Indiana Attorney General and the Indiana Department of Environmental Management, and NIPSCO.

45) "Plaintiff(s)" means the United States, including the EPA and the United States Department of Justice, and the State of Indiana, including the Indiana Attorney General and the Indiana Department of Environmental Management ("IDEM").

46) "PM Control Device" means any device, including an ESP or a fullstream baghouse, that reduces emissions of particulate matter ("PM").

47) "PM" means particulate matter.

48) “PM Continuous Emission Monitoring System” and “PM CEMS” mean the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM emissions.

49) “PM Emission Rate” means the number of pounds of PM emitted per million BTU of heat input (“lb/mmBTU”).

50) “Project Dollars” means NIPSCO’s expenditures and payments incurred or made in carrying out the Environmental Mitigation Projects identified in Section X (Environmental Mitigation Projects) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section X (Environmental Mitigation Projects) and Appendix A of this Consent Decree; and (b) constitute NIPSCO’s direct payments for such projects, NIPSCO’s external costs for contractors, vendors, and equipment, or NIPSCO’s internal costs consisting of employee time, travel, or out-of-pocket expenses specifically attributable to these particular projects and documented in accordance with GAAP.

51) “PSD” means Prevention of Significant Deterioration program within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492 and 40 C.F.R. Part 52, as well as any PSD provisions of the Indiana SIP.

52) “Retire” or “Retirement” means to permanently cease to operate, physically render inoperable, and relinquish all Clean Air Act permits for a Unit within the NIPSCO System.

53) “Selective Catalytic Reduction System” and “SCR” mean a pollution control device that employs selective catalytic reduction technology for the reduction of NO_X emissions.

54) "Selective Non-Catalytic Reduction System" and "SNCR" mean a pollution control device that employs selective non-catalytic reduction technology for the reduction of NO_X emissions.

55) "SO_2" means sulfur dioxide.

56) "SO_2 Allowance" means "allowance" as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide."

57) "Surrender" means permanently surrendering NOx or SO_2 allowances so that such NOx or SO2 allowances can never be used to meet any compliance requirement under the Clean Air Act, the Indiana SIP, or this Consent Decree.

58) "Title V Permit" means the permit required for NIPSCO's major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661f.

59) "Unit" means, collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment, at or serving a coal-fired steam electric generating unit. An electric steam generating station may comprise one or more Units.

IV. <u>NO_X EMISSION REDUCTIONS AND CONTROLS</u>

A. <u>NO_X Emission Controls</u>

60) Commencing for each Unit on the dates set forth in Table 1 below, NIPSCO shall Continuously Operate the NOx control technology at each Unit in the

NIPSCO System as stated in Table 1 and achieve and continuously maintain the 30-Day Rolling Average Emission Rates for NOx set forth in Table 1.

Table 1

Unit	Control Technology	30-Day Rolling Average Emission Rate (lb/mmBTU)	Date required to meet 30-Day Rolling Average Emission Rate
Bailly Units 7 and 8	Bailly Unit 7 SCR; Bailly Unit 8 SCR	0.180	March 31, 2011
Michigan City Unit 12	SCR	0.160	March 31, 2011
	NOx Option A: SCR NOx Option B: Retire	NOx Option A: 0.160 NOx Option B: N/A	December 31, 2018
Schahfer Unit 14	SCR	0.160	March 31, 2011
Schahfer Unit 15	LNB/OFA	0.180	January 31, 2011
	NOx Option 1: SCR NOx Option 2: SNCR	NOx Option 1: 0.080 NOx Option 2: 0.150	NOx Option 1: December 31, 2015 NOx Option 2: December 31, 2012
Schahfer Unit 17	LNB/OFA	0.200	March 31, 2011
Schahfer Unit 18	LNB/OFA	0.200	March 31, 2011

61) By December 31, 2014, NIPSCO shall notify EPA of its decision to implement either NOx Option A or NOx Option B for Michigan City Unit 12 as described in Table 1.

62) By December 31, 2011, NIPSCO shall notify EPA of its decision to implement either NOx Option 1 or NOx Option 2 for Schahfer Unit 15 as described in Table 1.

63) Commencing for each Cyclone-fired Unit on the dates set forth in Table 2 below, NIPSCO shall Continuously Operate the NOx control technology at each Cyclone-fired Unit in the NIPSCO System as stated in Table 2 and achieve and continuously maintain the 365-Day Rolling Average Emission Rates for NOx set forth in Table 2.

Table 2

Unit	Control Technology	365-Day Rolling Average Emission Rate (lb/mmBTU)	Date required to meet 365-Day Rolling Average Emission Rate
Bailly Units 7 and 8	Bailly Unit 7 SCR; Bailly Unit 8 SCR	0.150	December 31, 2010
		0.130	December 31, 2013
		0.120	December 31, 2015
Michigan City Unit 12	SCR	0.140	December 31, 2010
		0.120	December 31, 2011
		0.100	December 31, 2013
Schahfer Unit 14	SCR	0.140	December 31, 2010
		0.120	December 31, 2012
		0.100	December 31, 2014

64) Beginning forty five (45) days from the Date of Entry of this Consent Decree, NIPSCO shall Continuously Operate low NOx burners ("LNB") and/or OFA on the NIPSCO System Units according to Table 3 below.

Table 3

NIPSCO System Unit	**NOx Control Technology**
Bailly Unit 7	OFA
Bailly Unit 8	OFA
Michigan City Unit 12	OFA
Schahfer Unit 14	OFA
Schahfer Unit 15	LNB/OFA
Schahfer Unit 17	LNB/OFA

Schahfer Unit 18	LNB/OFA

65) With prior written notice to the Plaintiffs and written approval from EPA (after consultation by EPA with the State of Indiana), NIPSCO may, in lieu of installing and operating SCR or SNCR technology at a Unit, install and operate at that Unit equivalent NOx control technology so long as such equivalent NOx control technology has been demonstrated to be capable of achieving and maintaining a 30-Day Rolling Average Rate for NOx of not more than 0.080 lb/mmBTU for that NIPSCO Unit. If NIPSCO elects to install and operate equivalent NOx control technology at a Unit, it must commence operation of the equivalent NOx control technology at that Unit by the date specified for SCR or SNCR installation in Table 1 or Table 2. Upon installation of such equivalent NOx control technology at a Unit as a means of complying with Table 1 or 2, NIPSCO shall Continuously Operate and achieve and maintain a 30-Day Rolling Average Emission Rate for NOx of not more than 0.080 lb/mmBTU at that Unit.

B. General NO_X Provision

66) In determining Emission Rates for NO_X, NIPSCO shall use CEMS in accordance with the procedures of 40 C.F.R. Part 75.

C. Annual System Tonnage Limitation for NO_X

67) In addition to meeting the emission limits set forth in Tables 1 and 2, all Units in the NIPSCO System, collectively, shall not emit NO_X in excess of the Annual System Tonnage Limitations calculated on a calendar-year basis set forth in Table 4.

Table 4:

Applicable Calendar Year	**Annual NIPSCO System Tonnage Limitation for NO_X**
2011	15,825 tons
2012	15,537 tons
2013	If NIPSCO selects NOx Option 1 in Table 1 (SCR on Schahfer Unit 15): 15,247 tons If NIPSCO selects NOx Option 2 in Table 1(SNCR on Schahfer Unit 15): 13,752 tons
2014	If NIPSCO selects NOx Option 1 in Table 1 (SCR on Schahfer Unit 15): 14,959 tons If NIPSCO selects NOx Option 2 in Table 1 (SNCR on Schahfer Unit 15): 13,464 tons
2015	If NIPSCO selects NOx Option 1 in Table 1 (SCR on Schahfer Unit 15): 14,365 tons If NIPSCO selects NOx Option 2 in Table 1 (SNCR on Schahfer Unit 15): 12,870
2016	If NIPSCO selects NOx Option 1 in Table 1 (SCR on Schahfer Unit 15): 11,704 tons If NIPSCO selects NOx Option 2 in Table 1 (SNCR on Schahfer Unit 15): 12,870
2017	Same as 2016

2018	Same as 2016
2019 and every year thereafter	If NIPSCO selects NOx Option 2 and NOx Option A in Table 1 (SNCR on Schahfer Unit 15 and SCR on Michigan City Unit 12): 12,870 tons If NIPSCO selects NOx Option 2 and NOx Option B in Table 1 (SNCR on Schahfer Unit 15 and Retirement of Michigan City Unit 12): 11,470 If NIPSCO selects NOx Option 1 and NOx Option A in Table 1 (SCR on Schahfer Unit 15 and SCR on Michigan City Unit 12): 11,704 tons If NIPSCO selects NOx Option 1 and NOx Option B in Table 1 (SCR on Schahfer Unit 15 and Retirement of Michigan City Unit 12): 10,300 tons

68) Except as may be necessary to comply with Section XV (Stipulated Penalties), NIPSCO may not use NO_X Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation required by this Decree by using, tendering, or otherwise applying NO_X Allowances to offset any excess emissions (i.e., emissions above the limits specified in Table 1, Table 2 and Table 4).

D. Use and Surrender of NO_X Allowances

69) Except as provided in this Consent Decree, NIPSCO shall not sell or trade any NO_X Allowances allocated to the NIPSCO System that would otherwise be available

for sale or trade as a result of the actions taken by NIPSCO to comply with the requirements, as they become due, of this Consent Decree.

70) For any given calendar year, provided that NIPSCO is in compliance for that calendar year with all emissions limitations for NOx set forth in this Consent Decree, nothing in this Consent Decree, including the requirement to Surrender NOx allowances under Paragraph 71 of this Consent Decree, shall preclude NIPSCO from selling or trading NO_X Allowances allocated to the NIPSCO System that become available for sale or trade that calendar year solely as a result of:

a. the installation and operation at any time of any NOx pollution control technology or technique that is not otherwise required by this Consent Decree, or the installation and operation of NOx controls prior to the dates required under this Section IV of this Consent Decree; or

b. achievement and maintenance of a NO_X 30-Day Rolling Average Emission Rate at any non-cyclone NIPSCO System Unit, as determined on a unit by unit basis, below the emission rate specified for such Unit in Table 1; or for any NIPSCO Cyclone-fired Unit, as determined on a unit by unit basis, achievement and maintenance of a NOx 30-Day Rolling Average Emission Rate below 0.100 lb/mmBTU for such Cyclone-fired Unit, and a NOx 365-Day Rolling Average Emission Rate below the emission rate specified for such Cyclone-fired Unit in Table 2,

so long as NIPSCO timely reports the generation of such surplus NO_X Allowances that occur after the Date of Entry of this Consent Decree in accordance with Section XIII (Periodic Reporting) of this Consent Decree.

71) Beginning with calendar year 2011, and continuing each calendar year thereafter, NIPSCO shall Surrender to EPA, or transfer to a non-profit third party selected by NIPSCO for Surrender, all NOx Allowances allocated to the NIPSCO System Units for that calendar year that NIPSCO does not need in order to meet its own federal and/or state Clean Air Act statutory or regulatory requirements. This requirement to Surrender all such NOx Allowances allocated to NIPSCO for a given calendar year is subject to Paragraph 70 of this Consent Decree. NIPSCO shall make such Surrender annually, within forty-five (45) days of NIPSCO's receipt of the Annual Deduction Reports for NOx from EPA. Surrender need not include the specific NOx Allowances that were allocated to NIPSCO System Units, so long as NIPSCO Surrenders NOx Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under this Paragraph.

72) If any NOx allowances are transferred directly to a non-profit third party, NIPSCO shall include a description of such transfer in the next report submitted to EPA and the State of Indiana pursuant to Section XIII (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the NOx Allowances and a listing of the serial numbers of the transferred NOx Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the NOx Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any NOx Allowances, NIPSCO shall include a statement that the third-party recipient(s) Surrendered the NOx Allowances for permanent Surrender to EPA in accordance with the provisions of

Paragraph 71 within one (1) year after NIPSCO transferred the NOx Allowances to them. NIPSCO shall not have complied with the NOx Allowance Surrender requirements of this Paragraph until all third-party recipient(s) shall have actually Surrendered the transferred NOx Allowances to EPA.

73) For all NOx Allowances Surrendered to EPA, NIPSCO or the third-party recipient(s) (as the case may be) shall first submit a NOx Allowance transfer request form to the EPA Office of Air and Radiation's Clean Air Markets Division ("CAMD") directing the transfer of such NOx Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, NIPSCO or the third-party recipient(s) shall irrevocably authorize the transfer of these NOx Allowances and identify by name of account and any applicable serial or other identification numbers or station names the source and location of the NOx Allowances being Surrendered.

74) Nothing in this Consent Decree shall prevent NIPSCO from purchasing or otherwise obtaining NO_X Allowances from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law. Such allowances will not be used to demonstrate compliance with the annual tonnage caps of this Consent Decree.

75) The requirements in Paragraphs 69 through 74 of this Consent Decree pertaining to NIPSCO's use or Surrender of NO_X Allowances are permanent injunctions not subject to any termination provision of this Consent Decree.

V. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. SO_2 Emission Controls

76) Commencing for each Unit on the dates set forth in Table 5 below, NIPSCO shall Continuously Operate the FGDs at each Unit in the NIPSCO System as stated in Table 5 and achieve and continuously maintain the 30-Day Rolling Average Emission Rate or applicable SO_2 30-Day Rolling Average Removal Efficiency or Monthly SO_2 Removal Efficiency as set forth in Table 5.

Table 5

Unit	Control Technology	30-Day Rolling Average Emission Rate (lb/mmBTU) / Removal Efficiency & Monthly SO_2 Removal Efficiency	Date required to meet emission rate/removal efficiency
Bailly Units 7 and 8	Upgrade existing FGD on Bailly 7 and 8 main stack	95.0% Monthly SO_2 Removal Efficiency	January 1, 2011
		97.0% 30-Day Rolling Average SO2 Removal Efficiency or 95.0% 30-Day Rolling Average SO_2 Removal Efficiency if Bailly Units 7 and 8 burn only Low Sulfur Coal for that entire 30-day period	January 1, 2014
Michigan City Unit 12	SO_2 Option 1: Retire SO_2 Option 2: FGD	SO_2 Option 1: N/A SO_2 Option 2: 0.100 lb/mmbtu 30-Day Rolling Average Emission Rate	December 31, 2018
Schahfer Unit 14	FGD	0.080 lb/mmbtu 30-Day Rolling Average Emission Rate	December 31, 2013
Schahfer Unit 15	FGD	0.080 lb/mmbtu 30-Day Rolling Average Emission Rate	December 31, 2015
Schahfer Unit 17	Upgrade existing FGD	97.0 % 30-Day Rolling Average Removal Efficiency	January 31, 2011
Schahfer Unit 18	Upgrade	97.0 % 30-Day Rolling Average	January 31, 2011

	existing FGD	Removal Efficiency	

77) By December 31, 2014, NIPSCO shall notify EPA of its decision to implement either SO_2 Option 1 or SO_2 Option 2 for Michigan City Unit 12 as described in Table 5.

78) NIPSCO utilizes a main stack (CS00001) through which air emissions from both Bailly Units 7 and 8 are routed. NIPSCO has in place an existing contract with Pure Air, a separate entity, under which Pure Air owns and operates an FGD controlling SO2 emissions from Bailly Units 7 and 8. This FGD controls SO_2 emissions from both Bailly Units 7 and 8. During periods of startup, the FGD and the main stack cannot be used for the unit(s) experiencing startup. When either or both Bailly Units 7 and 8 are experiencing startup, emissions from the unit(s) experiencing startup are routed through a bypass stack that serves Bailly Unit 7 and Unit 8 around the FGD and these emissions are not controlled by the FGD. While combusting fuel, emissions from a Bailly unit shall be routed through the FGD unless that unit is experiencing startup. The following restrictions shall apply to NIPSCO's use of the bypass stack:

a. While combusting fuel, NIPSCO shall not use the Bailly Unit 7 and Unit 8 bypass stack for any emission purpose other than during periods of startup, and then may only use it for the unit(s) experiencing startup.

b. All SO_2 emissions associated with periods of startup are included in the calculation of the Monthly SO_2 Removal Efficiency and 30-Day Rolling Average SO_2 Removal Efficiency for Bailly Unit 7 and 8 as described in Table 5, except that NIPSCO may exclude from that calculation those

startup emissions from a unit that occur up until that unit reaches a temperature of 280 degrees Fahrenheit as measured at the outlet of the precipitator, not to exceed 16 hours in duration per startup while combusting coal. NIPSCO may however, exclude from the relevant removal efficiency, startup emissions that occur after the 16th hour up to the 24th hour, if NIPSCO Surrenders SO_2 Allowances in an amount equal to the difference between the actual tons of SO_2 emitted from the bypass stack between hour 17 and the point in time NIPSCO ceases use of the bypass stack for startup emissions (but, in any event, no longer than hour 24) and the tons of SO_2 emissions that would have been emitted assuming compliance with the relevant removal efficiency for Bailly Unit 7 and 8 specified in Table 5. In addition, NIPSCO may only exclude these limited unit startup emissions for the Bailly bypass stack if NIPSCO demonstrates to EPA that such emissions otherwise would cause NIPSCO to violate the relevant removal efficiency for Bailly Unit 7 or 8 as described in Table 5. Such demonstration shall require that NIPSCO, at minimum, provide EPA with calculations of emissions with and without bypass stack emissions;

c. NIPSCO shall limit the use of the bypass stack to the greatest extent practicable;

d. NIPSCO shall operate the bypass stack consistent with good engineering and maintenance practices for minimizing emissions to the extent practicable; and

e. Annual System Tonnage Limitations in Tables 4 and 6 shall apply during all periods of emissions, including all periods of bypass stack emissions.

79) In the event that the Monthly SO2 Removal Efficiency requirements for Bailly Unit 7 and Unit 8 as listed in Table 5 are not achieved for any given Calendar Month prior to January 1, 2014 after applying Paragraph 78, as applicable, NIPSCO may nonetheless remain in compliance with the requirements of this Section V (SO_2 Emissions Reduction and Controls) by Surrendering the number of SO2 Allowances equal to two times (2x) the difference between the actual tons of SO2 emitted from the Bailly main stack (CS001) during such Calendar Month minus the tons of SO2 emissions that would have been emitted from that stack during that Calendar Month had NIPSCO complied with the applicable Monthly SO2 Removal Efficiency specified in Table 5. In all cases where the applicable Monthly SO_2 Removal Efficiency is not achieved for a given Calendar Month prior to January 1, 2014, the difference between the actual SO_2 emissions emitted and the compliance level of SO_2 emissions during such Calendar Month shall be rounded up to the next highest ton (e.g., if the difference is 750 pounds, then the difference shall be rounded up to one ton and SO_2 Allowances equal to two tons would be required to be retired). Any allowances retired under this Paragraph 79 shall be in addition to any allowances that NIPSCO is otherwise required to Surrender to EPA or transfer to a non-profit third party pursuant to Paragraph 86 and 87 of this Consent Decree. After January 1, 2014, the method described in this Paragraph 79 may not be used to comply with the requirements of this Section.

80) After prior written notice to the Plaintiffs and prior written approval from EPA (after consultation by EPA with the State of Indiana), NIPSCO may, in lieu of

installing and operating FGD technology at Schahfer Unit 15, install and operate equivalent SO_2 control technology, so long as such equivalent SO_2 control technology has been demonstrated to be capable of achieving and maintaining a 30-Day Rolling Average Rate for SO_2 of not more than 0.080 lb/mmBTU, and so long as NIPSCO commences operation of the equivalent SO_2 control technology by the date specified for FGD installation in Table 5. If it elects to request equivalent SO_2 technology, NIPSCO shall provide the written notice referenced above no later than December 31, 2012. Upon installation of such equivalent SO_2 control technology as a means of complying with Table 5, NIPSCO shall achieve and maintain a 30-Day Rolling Average Emission Rate for SO_2 of not more than 0.080 lb/mmBTU at that Unit.

B. General SO2 Provisions

81) In determining Emission Rates for SO_2, NIPSCO shall use CEMS in accordance with the procedures of 40 C.F.R. Part 75.

C. Annual System Tonnage Limitation for SO_2

82) In addition to meeting the emission limits set forth in Table 5, all Units in the NIPSCO System, collectively, shall not emit SO_2 in excess of the Annual System Tonnage Limitations calculated on a calendar-year basis set forth in Table 6.

Table 6:

Applicable Calendar Year	Annual NIPSCO System Tonnage Limitation for SO_2
2011	50,200 tons
2012	Same as 2011

2013	Same as 2011
2014	35,900 tons
2015	Same as 2014
2016	25,300 tons
2017	Same as 2016
2018	Same as 2016
2019 and thereafter	If NIPSCO selects SO_2 Option 2 (Michigan City Unit 12 FGD): 11,600 tons If NIPSCO selects SO_2 Option 1 (Retirement of Michigan City Unit 12): 10,200 tons

83) Except as may be necessary to comply with Section XV (Stipulated Penalties), and except as permitted or required under Paragraphs 78 and 79, NIPSCO may not use SO_2 Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation required by this Decree by using, tendering, or otherwise applying SO_2 Allowances to offset any excess emissions (i.e., emissions above the limits specified in Table 5 and Table 6).

D. Use and Surrender of SO_2 Allowances

84) Except as provided in this Consent Decree, NIPSCO shall not sell or trade any SO_2 Allowances allocated to the NIPSCO System that would otherwise be available for sale or trade as a result of the actions taken by NIPSCO to comply with the requirements, as they become due, of this Consent Decree.

85) For any given calendar year, provided that the NIPSCO System is in compliance for that calendar year with all emissions limitations for SO_2 set forth in this Consent Decree, nothing in this Consent Decree, including the requirement to Surrender SO_2 Allowances under Paragraph 86 of this Consent Decree, shall preclude NIPSCO from selling or trading SO_2 Allowances allocated to the NIPSCO System that become available for sale or trade that calendar year solely as a result of:

a. the installation and operation of any pollution control technology or technique that is not otherwise required by this Consent Decree, or the installation and operation of any FGD prior to the dates required by Section V of this Consent Decree; or

b. achievement and maintenance of an SO_2 30-Day Rolling Average Removal Efficiency, 30-Day Rolling Average Emission Rate, or Monthly SO2 Removal Efficiency at any NIPSCO System Unit, as determined on a unit by unit basis, at a higher removal efficiency than the SO_2 30-Day Rolling Average Removal Efficiency or Monthly SO_2 Removal Efficiency specified for such Unit, or below the SO_2 30-Day Rolling Average Emission Rate specified for such Unit,

so long as NIPSCO timely reports the generation of such surplus SO_2 Allowances that occur after the Date of Entry of the Consent Decree in accordance with Section XIII (Periodic Reporting) of this Consent Decree.

86) Beginning with calendar year 2011, and continuing each calendar year thereafter, NIPSCO shall Surrender to EPA, or transfer to a non-profit third party selected by NIPSCO for Surrender, all SO_2 Allowances allocated to the NIPSCO System Units for

that calendar year that NIPSCO does not need in order to meet its own federal and/or state Clean Air Act statutory or regulatory requirements. This requirement to Surrender all such SO_2 Allowances is subject to Paragraph 85 of this Consent Decree. NIPSCO shall make such Surrender annually, within forty-five (45) days of NIPSCO's receipt of the Annual Deduction Reports for SO_2 from EPA. Surrender need not include the specific SO_2 Allowances that were allocated to NIPSCO System Units, so long as NIPSCO surrenders SO_2 Allowances that are from the same year or an earlier year and that are equal to the number required to be surrendered under this Paragraph.

87) If any allowances are transferred directly to a non-profit third party, NIPSCO shall include a description of such transfer in the next report submitted to EPA and the State of Indiana pursuant to Section XIII (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the SO_2 Allowances and a listing of the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO_2 Allowances, NIPSCO shall include a statement that the third-party recipient(s) Surrendered the SO_2 Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 86 within one (1) year after NIPSCO transferred the SO_2 Allowances to them. NIPSCO shall not have complied with the SO_2 Allowance Surrender requirements of this Paragraph until all third-party recipient(s) shall have actually Surrendered the transferred SO_2 Allowances to EPA.

88) For all SO_2 Allowances surrendered to EPA, NIPSCO or the third-party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request form to the EPA Office of Air and Radiation's Clean Air Markets Division ("CAMD") directing the transfer of such SO_2 Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, NIPSCO or the third-party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify by name of account and any applicable serial or other identification numbers or station names the source and location of the SO_2 Allowances being surrendered.

89) Nothing in this Consent Decree shall prevent NIPSCO from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law. Such allowances shall not be used to demonstrate compliance with the annual tonnage caps of this Consent Decree.

90) The requirements in Paragraphs 84 through 89 of this Decree pertaining to NIPSCO's surrender of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree.

VI. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of PM Emission Controls

91) Beginning ninety (90) days after the Date of Entry of this Consent Decree, and continuing thereafter, NIPSCO shall Continuously Operate each PM Control Device on each Unit within the NIPSCO System, to maximize the PM emission reductions at all times when the unit is in operation, provided that such operation of the PM Control Device is

consistent with the technological limitations, manufacturer's specifications and good engineering and maintenance practices for the PM Control Device. During any periods when any section or compartment of the PM control device is not operational, NIPSCO will minimize emissions to the extent practicable (as defined in 40 C.F.R. § 60.11(d)). Notwithstanding the foregoing sentences of this Paragraph 91, NIPSCO shall not be required to operate an ESP on any Unit if a fullstream baghouse is installed and operating to replace the ESP . Specifically, NIPSCO shall, at a minimum, to the extent practicable, and where applicable: (a) energize each available section of the ESP for each Unit, or at each Unit where a baghouse is installed, operate each compartment of the baghouse for each such Unit, regardless of whether that action is needed to comply with opacity limits; (b) maintain the energy or power levels delivered to the ESPs for each Unit to achieve optimal removal of PM, or at each Unit where a baghouse is installed, maintain and replace bags on each baghouse as needed to maximize collection efficiency; (c) at each Unit inspect the ESP or the baghouse (at any Unit where a baghouse is installed) for any openings or leakage in the casings, ductwork and expansion joints, and make best efforts to expeditiously repair and return to service any ESP section or baghouse compartment needing repair; (d) at each Unit where no baghouse is installed or operating, operate automatic control systems on the ESP, including the plate-cleaning and discharge electrode cleaning systems, to maximize control efficiency; and (e) at each Unit where a baghouse is installed and operating, make best efforts to expeditiously repair and return to service any failed baghouse compartment.

B. PM Emissions

92) Beginning for each Unit on the dates specified in Table 7 below, NIPSCO shall achieve and maintain a PM Emission Rate of no greater than 0.030 lb/mmBTU. If NIPSCO installs a fullstream baghouse on any of the Units identified in Table 7 to replace an existing ESP, pursuant to Paragraph 91 above, NIPSCO shall, upon installation of such baghouse, achieve and maintain a PM Emission Rate of no greater than 0.015 lb/mmBTU.

Table 7

NIPSCO System Unit	Date
Bailly Units 7 and 8 Main Stack (CS001)	December 31, 2010
Michigan City Unit 12	December 31, 2018
Schahfer Unit 14	December 31, 2013
Schahfer Unit 15	December 31, 2015
Schahfer Unit 17	December 31, 2010
Schahfer Unit 18	December 31, 2010

C. PM Emissions Testing

93) Beginning in calendar year 2011 and continuing in each calendar year thereafter, NIPSCO shall conduct a PM performance test on each NIPSCO System Unit identified in Table 7. The annual performance test requirement imposed on NIPSCO by this Paragraph may be satisfied by stack tests conducted by NIPSCO as may be required by its permits from the State of Indiana for any year that such stack tests are required under the permits. NIPSCO may perform testing every other year, rather than every year, provided

that two of the most recently completed test results from tests conducted in accordance with the methods and procedures specified in this Paragraph demonstrate that the PM emissions are equal to or less than 0.015 lb/mmBTU. NIPSCO shall perform testing every year, rather than every other year, beginning in the year immediately following any test result demonstrating that the PM emissions are greater than 0.015 lb/mmBTU.

D. General PM Provision

94) The reference methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, or an alternative method that is promulgated by EPA, requested for use herein by NIPSCO, and approved for use herein by EPA and IDEM. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. §§ 60.48a (b) and (e), or any federally approved method contained in the Indiana SIP. NIPSCO shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f). The results of each PM stack test shall be submitted to EPA and IDEM within forty-five (45) days of completion of each test.

VII. UNIT RETIREMENT

95) No later than December 31, 2010, NIPSCO shall Retire Mitchell Units 4, 5, 6, and 11.

96) If NIPSCO elects to Retire any Unit within the NIPSCO System other than Michigan City Unit 12 or Mitchell Units 4,5,6, and 11, such Retirement shall not alter the Annual System Tonnage Limitations as described in Tables 4 and 6.

VIII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

97) Emission reductions that result from actions to be taken by NIPSCO after the Date of Entry of this Consent Decree to comply with the requirements of this Consent Decree shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting or offset credit under the Clean Air Act's Nonattainment NSR and PSD programs.

98) The limitations on the generation and use of netting credits or offsets set forth in the previous Paragraph 97 do not apply to emission reductions achieved by NIPSCO System Units that are greater than those required under this Consent Decree. For purposes of this Paragraph, emission reductions from a NIPSCO System Unit are greater than those required under this Consent Decree if, for example, they result from NIPSCO's compliance with federally enforceable emission limits that are more stringent than those limits imposed on the NIPSCO System and individual Units under this Consent Decree and under applicable provisions of the Clean Air Act or the Indiana SIP.

99) Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by the State of Indiana or EPA as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS.

100) Nothing in this Consent Decree precludes any emissions from any NIPSCO System Units that occur either prior to the Date of Entry of this Consent Decree or thereafter from being considered in any modeling analyses required pursuant to 40 C.F.R. Part 52 or the Prevention of Significant Deterioration regulations under the Indiana

SIP for purposes of demonstrating compliance with PSD increments or air quality related values, including visibility, in a Class I area.

IX. PM AND MERCURY CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

101) Within eighteen months after the Date of Entry of this Consent Decree, or within 90 days of EPA's approval of NIPSCO's timely submittal under Paragraph 104, whichever is later, NIPSCO shall install, certify, maintain, and operate two PM CEMS and two mercury CEMS. NIPSCO shall install each PM CEMS and mercury CEMS such that representative measurements of emissions are obtained from the monitored unit(s). Each CEMS shall complete a minimum of one cycle of operations (sampling, analyzing and data recording) for each successive 15-minute period. Except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, NIPSCO shall continuously operate the PM CEMS and mercury CEMS consistent with technical limitations and manufacturer specifications.

102) The PM CEMS identified in Paragraph 101 above, shall be installed at NIPSCO's Michigan City Unit 12 and Schahfer Unit 15. The PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on a continuous basis. NIPSCO shall install a diluent monitoring system on Michigan City Unit 12 and Schahfer Unit 15 such that the PM mass concentration can be converted to units of lb/mmBTU. NIPSCO shall certify the two PM CEMS in accordance with 40 C.F.R. Part 60, Appendix B, Performance Specification 11. NIPSCO shall submit installation plans, operation plans and perform testing and reporting in accordance with Paragraphs 104 through 106 of this Consent Decree. In the event NIPSCO elects to retire

Michigan City Unit 12, PM CEMS shall be installed on Schahfer Unit 14 in accordance with the requirements of this Paragraph prior to the retirement of Michigan City Unit 12.

103) The mercury CEMS identified in Paragraph 101 shall be installed at NIPSCO's Michigan City Unit 12 and Schahfer Unit 15. The mercury CEMS shall be comprised of a continuous total vapor phase mercury monitoring device which measures total vapor phase mercury concentration, directly or indirectly, on a continuous basis. NIPSCO shall install a diluent monitoring system on Michigan City Unit 12 and Schahfer Unit 15, such that the mercury concentrations can be converted to units of pounds per trillion BTU (lb-mercury/TBTU) on an hourly average basis. NIPSCO shall certify the Mercury CEMS in accordance with 40 C.F.R. Part 60, Appendix B, Performance Specification 12a. NIPSCO shall submit installation plans, operation plans and perform testing and reporting in accordance with Paragraphs 104 through 106 of this Consent Decree. In the event NIPSCO elects to retire Michigan City Unit 12, mercury CEMS shall be installed on Schahfer Unit 14 in accordance with the requirements of this Paragraph prior to the retirement of Michigan City Unit 12.

104) Within six (6) months after the Date of Entry of this Consent Decree, NIPSCO shall submit to EPA for review and approval pursuant to Section XIV (Review and Approval of Submittals) of this Consent Decree the following information regarding the PM and mercury CEMS: (a) a plan for the installation, certification and operation of the CEMS; and (b) no less than six (6) months prior to conducting tests in accordance with Paragraph 105 of this Consent Decree a proposed QA/QC protocol that shall be followed in calibrating each PM CEMS and mercury CEMS. In developing both the plan for installation and certification of the PM and mercury CEMS and the QA/QC protocol,

NIPSCO shall use the criteria set forth in 40 C.F.R. Part 60, Appendix B (PS 11 and PS 12a). EPA shall expeditiously review such submissions. Following approval by EPA, NIPSCO shall thereafter operate the PM and mercury CEMS in accordance with the approved protocols.

105) No later than ninety days (90) after the deadline imposed by Paragraph 101, or within 90 days after EPA's approval of NIPSCO's submittals pursuant to Paragraph 104, whichever is later, NIPSCO shall conduct tests on each PM CEMS and mercury CEMS to demonstrate compliance with the CEMS installation and certification plan submitted to and approved by EPA in accordance with Paragraph 104. NIPSCO shall submit the results of all certification testing (including incomplete testing and associated Reference Method Testing) to EPA and IDEM within forty-five (45) days of completion of certification testing

106) Upon completion of testing in accordance with Paragraph 105 above, NIPSCO shall begin and continue to report to EPA, pursuant to Section XIII (Periodic Reporting), the data recorded by the PM and mercury CEMS, expressed in lb-PM/mmBTU and lb-mercury/TBTU, respectively. The data shall be reported as a three-hour rolling average basis in electronic format, as required by Section XIII, and shall include: each exceedance of an applicable PM mass emission limit (including those occurring during startup, shutdown and/or Malfunction), the magnitude of each exceedance, the date and time of commencement and completion of each period of exceedance, the process operating time during the reporting period, the nature and cause of each exceedance, the corrective action(s) taken or preventative measure(s) adopted in response to each exceedance, the date and time of each period during which any of the CEMS were

inoperative (except for zero and span checks), and the nature of system repairs or adjustments. For purposes of this Consent Decree, stack testing pursuant to Paragraph 94 shall be the method to determine compliance with the PM Emission Rate established by this Consent Decree. However, data from the PM CEMS shall be used to, at a minimum, monitor progress in reducing PM emissions.

107) Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 40 C.F.R. § 52.12(c) (62 Fed. Reg. 8,315; Feb. 27, 1997)) concerning the use of data for any purpose under the Act.

X. ENVIRONMENTAL MITIGATION PROJECTS

108) NIPSCO shall implement the Environmental Mitigation Projects ("Projects") described in Appendix A to this Consent Decree in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree. NIPSCO shall submit plans for the Projects to Plaintiffs for review and approval pursuant to Section XIV (Review and Approval of Submittals) of this Consent Decree in accordance with the schedules set forth in Appendix A. In implementing the Projects, NIPSCO shall spend no less than $9.5 million in Project Dollars within five (5) years of the Date of Entry of this Consent Decree. NIPSCO shall maintain, and present to Plaintiffs upon request, all documents to substantiate the Project Dollars expended and shall provide these documents to Plaintiffs within thirty (30) days of a request.

109) All plans and reports prepared by NIPSCO pursuant to the requirements of this Section of the Consent Decree and required to be submitted to EPA shall be publicly available from NIPSCO without charge.

110) NIPSCO shall certify, as part of each plan submitted to Plaintiffs for any Project, that NIPSCO is not otherwise required by law to perform the Project described in the plan, that NIPSCO is unaware of any other person who is required by law to perform the Project, and that NIPSCO will not use any Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law, including any applicable renewable portfolio standards or energy conservation standards.

111) NIPSCO shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

112) If NIPSCO elects (where such an election is allowed) to undertake a Project by contributing funds to another person or entity that will carry out the Project in lieu of NIPSCO, but not including NIPSCO's agents or contractors, that person or instrumentality must, in writing: (a) identify its legal authority for accepting such funding; and (b) identify its legal authority to conduct the Project for which NIPSCO contributes the funds. Regardless of whether NIPSCO elected (where such election is allowed) to undertake a Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, NIPSCO acknowledges that it will receive credit for the expenditure of such funds as Project Dollars only if NIPSCO demonstrates that the funds have been actually spent by either NIPSCO or by the person or instrumentality receiving them (or, in the case of internal costs, have actually been incurred by NIPSCO), and that such expenditures met all requirements of this Consent Decree.

113) Beginning six (6) months after the Date of Entry of this Consent Decree, and continuing until completion of each Project (including any applicable periods of

demonstration or testing), NIPSCO shall provide Plaintiffs with semi-annual updates concerning the progress of each Project.

114) Within sixty (60) days following the completion of each Project required under this Consent Decree (including any applicable periods of demonstration or testing), NIPSCO shall submit to Plaintiffs a report that documents the date that the Project was completed, NIPSCO's results from implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by NIPSCO in implementing the Project (including the emission reductions achieved for SO2, NOx, PM, and CO2).

115) In connection with any communication to the public or to shareholders regarding NIPSCO's actions or expenditures relating in any way to the Environmental Mitigation Projects in this Consent Decree, NIPSCO shall include prominently in the communication the information that the actions and expenditures were required as part of a consent decree to resolve allegations that NIPSCO violated the Clean Air Act.

XI. CIVIL PENALTY

116) Within thirty (30) calendar days after the Date of Entry of this Consent Decree, NIPSCO shall pay to the United States and the State of Indiana a civil penalty in the amount of $3.5 million, as follows:

(a) NIPSCO shall pay a civil penalty of $ 3.3 million to the United States. The civil penalty to the United States shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing DOJ Case Number 90-5-2-1-08417 and the civil action case name and case number of this action. The costs of such

EFT shall be NIPSCO's responsibility. Payment shall be made in accordance with timely instructions provided to NIPSCO by the Financial Litigation Unit of the U.S. Attorney's Office for the Northern District of Indiana. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, NIPSCO shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and case number, to the Department of Justice and to EPA in accordance with Section XXI (Notices) of this Consent Decree.

(b) NIPSCO shall pay a civil penalty of $200,000 to the State of Indiana. Payment shall be made by check made out to the "Environmental Management Special Fund" and shall be mailed to:

Indiana Department of Environmental Management
Cashier- Mail Code 50-10C
100 North Senate Avenue
Indianapolis, IN 46204-2251

117) Failure to timely pay the civil penalty shall subject NIPSCO to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render NIPSCO liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

118) Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

XII. RESOLUTION OF PAST AND FUTURE CLAIMS

A. Resolution of Plaintiffs' Civil Claims

119) Claims of the United States Based on Modifications Occurring Before the Lodging of Decree. Entry of this Consent Decree shall resolve all civil claims of the United States under:

a. Parts C and D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515, and the implementing federal and state rules, including the Indiana SIP approved under Section 110 of the Act implementing Parts C or D of Subchapter I; and

b. Title V of the Clean Air Act, 42 U.S.C. §§ 7661-7661f, and the implementing Title V operating permit program, including regulations that EPA has approved and/or promulgated under the Act, but only to the extent that such claims are based on NIPSCO's failure to obtain or amend an operating permit or failure to submit or amend an operating permit application that reflects applicable requirements imposed under Parts C and D of Subchapter I of the Clean Air Act;

that arose from or are based on any modification that commenced at any NIPSCO System Unit prior to the Date of Lodging of this Consent Decree, including but not limited to those claims and modifications alleged in the Complaint filed by the Plaintiffs in this civil action and those claims and modifications asserted in the NOV issued by EPA to NIPSCO.

120) Claims of the State of Indiana Based on Modifications Occurring Before the Lodging of Decree. Entry of this Decree shall resolve all civil claims of the State of Indiana under:

a. Parts C and D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515, and the implementing federal and state rules, including all civil claims under Indiana regulations at 326 IAC 2-1 *et seq.* (Construction and Operating Permit Requirements), 326 IAC 2-2 *et seq*. (PSD Requirements) and 326 IAC 2-3 *et seq*. (Emission Offset), and any related Indiana statutes, including all versions of the Indiana major New Source Review program that existed at the time of the modifications alleged in the Complaint to any NIPSCO System Unit;

b. Indiana regulations at 326 IAC 2 that govern minor New Source Review and any related Indiana statutes, including any Indiana rule governing minor New Source Review that existed at the time of the modifications alleged in the Complaint to any NIPSCO System Unit; and

c. Indiana statutes as they specifically apply to the programs implemented pursuant to Subchapter V of the Act, as well as Indiana regulations at 326 IAC 2-7 *et seq*. (Part 70 Permit Program);

that arose from or are based on any modification that commenced at any NIPSCO System Unit prior to the Date of Lodging of this Consent Decree, including but not limited to those claims and modifications alleged in the Complaint filed by the Plaintiffs in this civil action and those claims and modifications asserted in the NOV issued by EPA to NIPSCO**.**

121) <u>Plaintiffs' Claims Based on Modifications After the Lodging of Decree.</u> Entry of this Consent Decree also shall resolve all civil claims of the United States and of the State of Indiana for pollutants, except sulfuric acid mist, regulated under Parts C and D of Subchapter I of the Clean Air Act, and under regulations promulgated as of the Date of

Lodging of this Consent Decree, where such claims are based on any modification completed before December 31, 2018, and

a. is commenced at any NIPSCO System Unit after the Date of Lodging; or

b. that this Consent Decree expressly directs NIPSCO to undertake.

The term "modification" as used in this Paragraph 121 shall have the meaning that term is given under the Clean Air Act or under the regulations promulgated thereunder as of the Date of Lodging of this Consent Decree. For purposes of this Paragraph 121, civil claims shall not include greenhouse gases (carbon dioxide, nitrous oxide, methane, hydroflurorcarbons, perfluorocarbons, and sulfur hexafluoride) even if greenhouse gases are pollutants regulated under Part C or D of Subchapter I of the Act, and under regulations promulgated thereunder.

122) Reopener. The resolution of the civil claims of the United States and the State of Indiana provided by this Subsection is subject to the provisions of Subsection B of this Section.

B. Pursuit of Plaintiffs' Civil Claims Otherwise Resolved

123) Bases for Pursuing Resolved Claims Across NIPSCO System. If NIPSCO violates an Annual Tonnage Limits in Tables 4 or 6, or fails by more than ninety (90) days to complete upgrading of the Bailly FGD or installation and commence operation of any emission control device required pursuant to this Consent Decree; or fails by more than ninety (90) days to retire and permanently cease to operate all Mitchell Units pursuant to Section VII (Unit Retirement), then the United States or the State of Indiana may pursue any claim at any NIPSCO System Unit that has otherwise been resolved under Subsection A of this Section, subject to (a) and (b) below.

a. For any claims based on modifications undertaken at an Other Unit (i.e. any Unit of the NIPSCO System that is not an Improved Unit for the pollutant in question), claims may be pursued only where the modification(s) on which such claim is based was commenced within the five years preceding the violation or failure specified in this Paragraph.

b. For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced: (i) after lodging of the Consent Decree, and (ii) within the five years preceding the violation or failure specified in this Paragraph.

124) Additional Bases for Pursuing Resolved Claims for modifications at an Improved Unit. Solely with respect to Improved Units, the United States or the State of Indiana may also pursue claims arising from a modification (or collection of modifications) at an Improved Unit that have otherwise been resolved under Section XII, Subsection A, if the modification (or collection of modifications) at the Improved Unit on which such claim is based: (i) was commenced after the Date of Lodging, and (ii) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

125) Additional Bases for Pursuing Resolved Claims for Modifications at an Other Unit. Solely with respect to Other Units, the United States or the State of Indiana may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that have otherwise been resolved under Section XII, Subsection A, if the

modification (or collection of modifications) on which the claim is based was commenced within the five years preceding any of the following events:

a. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging that increases the maximum hourly emission rate for such Other Unit for the relevant pollutant (only NO_x or SO_2) as measured by 40 C.F.R. § 60.14(b) and (h);

b. the aggregate of all Capital Expenditures paid at such Other Unit exceed $150/KW on the Unit's Boiler Island (based on the capacity numbers included in Paragraph 36) during January 1, 2011, through December 31, 2017. (Capital Expenditures shall be measured in calendar year 2009 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

c. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase:

   i. presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603;

   ii. causes or contributes to violation of a NAAQS in any Air Quality Control Area that is in attainment with that NAAQS;

   iii. causes or contributes to violation of a PSD increment; or

   iv. causes or contributes to any adverse impact on any formally recognized air quality and related values in any Class I area.

d. The introduction of any new or changed NAAQS shall not, standing alone, provide the showing needed under subparagraph (c) of this Paragraph to pursue any claim for a modification at an Other Unit resolved under Subsection A of this Section.

XIII. PERIODIC REPORTING

126) Pursuant to Paragraph 93 of this Consent Decree, NIPSCO shall conduct performance tests for PM that demonstrate compliance with the PM Emission Rate required by this Consent Decree with respect to NIPSCO System Units. Within forty-five (45) days of each such performance test, NIPSCO shall submit the results of the performance test to EPA and IDEM at the address specified in Section XXI (Notices) of this Consent Decree.

127) Beginning thirty (30) days after the end of the second calendar quarter following the Date of Entry of this Consent Decree, and continuing on a semi-annual basis until termination of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, NIPSCO shall submit to EPA a progress report containing the following information:

a. all information necessary to determine compliance with the requirements of the following Tables of this Consent Decree: Tables 1, 2, 3 and 4 concerning NO_X emissions; Tables 5 and 6 concerning SO_2 emissions (including information related to burning of low sulfur coal at Bailly Units 7 and 8); and Table 7 concerning PM emissions;

b. documentation of any Capital Expenditures at a Unit's Boiler Island made during the period covered by the progress report and cumulative Boiler Island Capital Expenditures to date;

c. all information relating to emission allowances and credits that NIPSCO claims to have generated in accordance with Paragraphs 70 and 85, through compliance beyond the requirements of this Consent Decree;

d. all information indicating the status of installation and commencement of operation of pollution controls, including information that the installation and commencement of operation of a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by NIPSCO to mitigate such delay;

e. all affirmative defenses asserted by NIPSCO pursuant to Section XVII (Affirmative Defense) for that quarter;

f. all information relating to excess emissions due to startup, shutdown, and Malfunction emissions, including steps taken to minimize the adverse effects of such excess emissions; and

g. information verifying compliance with:

   i. Continuous Operation of all pollution control equipment,

   ii. allowance Surrender requirements, including supporting calculations, and

   iii. optimization of any ESP's, including any periods during which all sections were not in service, the reasons therefore and actions taken to remedy such failure.

128) In any periodic progress report submitted pursuant to this Section, NIPSCO may incorporate by reference information previously submitted under its Title V permitting requirements, provided that NIPSCO attaches the Title V permit report, or the relevant portion thereof, and provides a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

129) In addition to the progress reports required pursuant to this Section, NIPSCO shall provide a written report to EPA of any violation of the requirements of this Consent Decree within fifteen (15) calendar days of when NIPSCO knew or should have known of any such violation. In this report, NIPSCO shall explain the cause or causes of the violation and all measures taken or to be taken by NIPSCO to prevent such violations in the future.

130) Each NIPSCO report shall be signed by NIPSCO's Vice President of Generation or his or her equivalent or designee of at least the rank of Vice President, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

131) If any Allowances are Surrendered to any third party pursuant to this Consent Decree, the third party's certification pursuant to Paragraphs 72 and 87, shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that,_____ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I

understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

XIV. REVIEW AND APPROVAL OF SUBMITTALS

132) Unless otherwise provided, NIPSCO shall submit each plan, report, or other submission required by this Consent Decree to Plaintiffs whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. Plaintiffs may approve the submittal or decline to approve it and provide written comments explaining the bases for declining such approval. Within sixty (60) days of receiving written comments from Plaintiffs, NIPSCO shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal to Plaintiffs; or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XVIII (Dispute Resolution) of this Consent Decree.

133) Upon receipt of EPA's final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, NIPSCO shall implement the approved submittal in accordance with the schedule specified therein or another EPA-approved schedule.

XV. STIPULATED PENALTIES

134) For any failure by NIPSCO to comply with the terms of this Consent Decree, and subject to the provisions of Sections XVI (Force Majeure), VXII (Affirmative Defenses) and XVIII (Dispute Resolution), NIPSCO shall pay, within thirty (30) days after receipt of written demand to NIPSCO by the United States, the following stipulated penalties to the United States:

Table 8

Consent Decree Violation	Stipulated Penalty
a. Failure to pay the civil penalty as specified in Section XI (Civil Penalty) of this Consent Decree.	$10,000 per day
b. Failure to comply with any applicable 30-Day Rolling Average Emission Rate for SO_2 or NOx, where the violation is less than 5% in excess of the limits set forth in this Consent Decree.	$2,500 per day per violation
c. Failure to comply with any applicable 30-Day Rolling Average Emission Rate for SO_2 or NOx, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree.	$5,000 per day per violation
d. Failure to comply with any applicable 30-Day Rolling Average Emission Rate for SO_2 or NOx, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree.	$10,000 per day per violation
e. Failure to comply with any applicable average Removal Efficiency for SO2 where the violation is equal to or less than 0.15% less than the applicable limit.	$2,500 per day per violation
f. Failure to comply with any applicable average Removal Efficiency for SO2 where the violation is greater than 0.15% but less than 0.3% less than the applicable limit.	$5,000 per day per violation
g. Failure to comply with any applicable average Removal Efficiency for SO2 where the violation is equal to or greater than 0.3% less than the applicable limit.	$10,000 per day per violation
h. Failure to comply with any applicable 365-Day Rolling Average Emission Rate for NOx, where the violation is less than 5% in excess of the limits set forth in this Consent Decree.	$350 per day of violation for a 365-Day Rolling Average Emission Rate violation, plus $4,000 for each subsequent 365-Day Rolling Average Emission Rate violation that includes any day in a previously assessed 365-Day Rolling Average Emission Rate violation (*e.g.*, if a violation of the 365-Day Rolling Average

	Emission Rate for a Unit first occurs on June 1, 2010, occurs again on June 2, 2010, and again on May 31, 2011, the total stipulated penalty assessed for these three violations would equal $135,750).
i. Failure to comply with any applicable 365-Day Rolling Average Emission Rate for NOx, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree.	$450 per day of violation for a 365-Day Rolling Average Emission Rate violation, plus $5,000 for each subsequent 365-Day Rolling Average Emission Rate violation that includes any day in a previously assessed 365-Day Rolling Average Emission Rate violation (*e.g.*, if a violation of the 365-Day Rolling Average Emission Rate for a Unit first occurs on June 1, 2010, occurs again on June 2, 2010, and again on May 31, 2011, the total stipulated penalty assessed for these three violations would equal $174,250).
j. Failure to comply with any applicable 365-Day Rolling Average Emission Rate for NOx, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree.	$600 per day of violation for a 365-Day Rolling Average Emission Rate violation, plus $6,000 for each subsequent 365-Day Rolling Average Emission Rate violation that includes any day in a previously assessed 365-Day Rolling Average Emission Rate violation (*e.g.*, if a violation of the 365-Day Rolling Average Emission Rate for a Unit first occurs on June 1, 2010, occurs again on June 2, 2010, and again on May 31, 2011, the total stipulated penalty assessed for these three violations would equal $231,000).
k. Failure to comply with the Annual Tonnage Limits	$5,000 per ton for the first 1000 tons, and $10,000 per ton for each

for SO_2.	additional ton above 1000 tons. In addition, NIPSCO shall Surrender, pursuant to the procedures set forth in Paragraph 86, SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
l. Failure to comply with the Annual Tonnage Limits for NO_X.	$5,000 per ton for the first 1000 tons, and $10,000 per ton for each additional ton above 1000 tons. In addition, NIPSCO shall Surrender, pursuant to the procedures set forth in Paragraph 71, NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded.
m. Operation of a Unit required under this Consent Decree to be equipped with any NO_X, SO_2, or PM control device without the operation of such device, to the extent operation of that control device is required under this Consent Decree.	$10,000 per day per violation during the first 30 days, $27,500 per day per violation thereafter
n. Failure to install or operate CEMS as required in this Consent Decree.	$1,000 per day per violation
o. Failure to conduct performance tests of PM emissions, as required in this Consent Decree.	$1,000 per day per violation
p. Failure to apply for any permit, or amendment or application therefor, required by Section XIX (Permits and SIP Revisions).	$1,000 per day per violation
q. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree.	$750 per day per violation during the first ten days, $1,000 per day per violation thereafter
r. Selling or trading NO_X Allowances except as permitted by Section IV. D (Use and Surrender of NOx Allowances).	The surrender of NO_X Allowances in an amount equal to four times the number of NO_X Allowances used, sold, or transferred in violation of this Consent Decree
s. Selling or trading SO_2 Allowances except as permitted	The surrender of SO_2 Allowances

by Section V.D (Use and Surrender of SO_2 Allowances).	in an amount equal to four times the number of SO_2 Allowances used, sold, or transferred in violation of this Consent Decree
t. Failure to Surrender NOx Allowances as required by Paragraph 71.	(a) $27,500 per day plus (b) $1,000 per NOx Allowance not surrendered
u. Failure to Surrender SO_2 Allowances as required by Paragraph 86.	(a) $27,500 per day plus (b) $1,000 per SO_2 Allowance not surrendered
v. Failure to demonstrate the third-party Surrender of an NOx Allowance in accordance with Paragraphs 72 and 73.	$2,500 per day per violation
w. Failure to demonstrate the third-party surrender of an SO_2 Allowance in accordance with Paragraphs 87 and 88.	$2,500 per day per violation
x. Failure to undertake and complete any of the Environmental Mitigation Projects in compliance with Section X (Environmental Mitigation Projects) of this Consent Decree.	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
y. Failure to notify EPA of its decision to adopt any NOx or SO2 Option pursuant to Tables 1 and 5.	$1,000 per day per violation
z. Violating an applicable PM Emission Rate based on the results of a stack test required pursuant to Paragraph 94 of this Consent Decree, where the violation is less than 5% in excess of the limit set forth in this Consent Decree.	$2,500 per day, starting on the day a stack test result demonstrates a violation and continuing each day thereafter until and excluding such day on which a subsequent stack test* demonstrates compliance with the applicable PM Emission Rate
aa. Violating an applicable PM Emission Rate based on the results of a stack test required pursuant to Paragraph 94 of this Consent Decree, where the violation is equal to or greater than 5% but less than 10% in excess of the limit set forth in this Consent Decree.	$5,000 per day, starting on the day a stack test result demonstrates a violation and continuing each day thereafter until and excluding such day on which a subsequent stack test* demonstrates compliance with the applicable PM Emission

	Rate
bb. Violating an applicable PM Emission Rate based on the results of a stack test required pursuant to Paragraph 94 of this Consent Decree, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree.	$10,000 per day, starting on the day a stack test result demonstrates a violation and continuing each day thereafter until and excluding such day on which a subsequent stack test* demonstrates compliance with the applicable PM Emission Rate
cc. Failure to optimize ESP or Baghouse pursuant to Paragraph 91.	$2,500 per day
dd. Any other violation of this Consent Decree	$1,000 per day per violation

*NIPSCO shall not be required to make any submission, including any notice or test protocol, or to obtain any approval to or from EPA or IDEM in advance of conducting such a subsequent stack test.

135) Violations of any limit based on a 30-Day Rolling Average constitute thirty (30) days of violation, but where such a violation (for the same pollutant and from the same Unit) recurs within periods less than thirty (30) Operating Days, NIPSCO shall not be obligated to pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

136) Violations of any limit based on a 365-Day Rolling Average constitute 365 days of violation, but where such a violation (for the same pollutant and from the same Unit) recurs within periods less than 365 Operating Days, NIPSCO shall not be obligated to pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

137) A violation of the Monthly SO_2 Removal Efficiency for a given Calendar Month shall constitute a violation on each day within the Month. For clarity, if NIPSCO Surrenders SO_2 allowances pursuant to Paragraph 79 of this Consent Decree as a means to

comply with the Monthly SO_2 Removal Efficiency requirement, there is no Monthly SO_2 Removal Efficiency violation.

138) All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases, whichever is applicable. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

139) NIPSCO shall pay all stipulated penalties to the United States within thirty (30) days of receipt of written demand to NIPSCO from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless NIPSCO elects within twenty (20) days of receipt of written demand to NIPSCO from the United States to dispute the obligation to pay or the accrual of stipulated penalties in accordance with the provisions in Section XVIII (Dispute Resolution) of this Consent Decree.

140) Stipulated penalties shall continue to accrue as provided in accordance with Paragraph 134 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XVIII (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid

within thirty (30) days of the effective date of the agreement or of the receipt of Plaintiffs' decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, NIPSCO shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with interest accrued on such penalties determined by the Court to be owing, except as provided in subparagraph (c) of this Paragraph; or

c. If the Court's decision is appealed by any Party, NIPSCO shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with interest accrued on such stipulated penalties determined to be owing by the appellate court.

Notwithstanding any other provision of this Consent Decree, the accrued stipulated penalties agreed by Plaintiffs and NIPSCO, or determined by Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 134.

141) All stipulated penalties shall be paid in the manner set forth in Section XI (Civil Penalty) of this Consent Decree.

142) Should NIPSCO fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

143) The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States or the State of Indiana by reason of NIPSCO's failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of this Consent Decree (for which this Consent Decree provides for payment of a stipulated penalty) that is also a violation of the Act, including the implementing Title V operating permit program, regulations EPA has approved and/or promulgated under the Act, the Indiana SIP, including Indiana regulations under 326 IAC Article 2, or of an operable Title V permit, NIPSCO shall be allowed a credit for stipulated penalties paid against any statutory or regulatory penalties also imposed for such violation.

XVI. FORCE MAJEURE

144) For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of NIPSCO, its contractors, or any entity controlled by NIPSCO that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite NIPSCO's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event: (a) as it is occurring; and (b) after it has occurred, such that the delay and violation are minimized to the greatest extent possible and the emissions during such event are minimized to the greatest extent possible. Specific references to Force Majeure in other parts of this Consent Decree do not restrict the ability of NIPSCO to assert Force Majeure pursuant to the process described in this section. .

145) Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which NIPSCO intends to assert a claim of Force Majeure, NIPSCO shall notify Plaintiffs in writing as soon as practicable, but in no event later than fourteen (14) business days following the date NIPSCO first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, NIPSCO shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by NIPSCO to prevent or minimize the delay or violation, the schedule by which NIPSCO proposes to implement those measures, and NIPSCO's rationale for attributing a delay or violation to a Force Majeure Event. A copy of this notice shall be sent electronically, as soon as practicable, to the U.S. Department of Justice, EPA, and IDEM. NIPSCO shall adopt all reasonable measures to avoid or minimize such delays or violations and any resulting emissions. NIPSCO shall be deemed to know of any circumstance which NIPSCO, its contractors, or any entity controlled by NIPSCO knew or should have known.

146) Failure to Give Notice. If NIPSCO fails to comply with the notice requirements of this Section, EPA may void NIPSCO's claim for Force Majeure as to the specific event for which NIPSCO has failed to comply with such notice requirement.

147) EPA's Response. EPA shall notify NIPSCO in writing regarding NIPSCO's claim of Force Majeure within twenty (20) business days of receipt of the notice provided under Paragraph 144. If EPA agrees that a delay in performance has been or will be caused by a Force Majeure Event, EPA and NIPSCO shall stipulate to an extension of

deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXV (Modification) of this Consent Decree.

148) Disagreement. If EPA does not accept NIPSCO's claim of Force Majeure, or if EPA and NIPSCO cannot agree on the length of the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XVIII (Dispute Resolution) of this Consent Decree.

149) Burden of Proof. In any dispute regarding Force Majeure, NIPSCO shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. NIPSCO shall also bear the burden of proving that NIPSCO gave the notice required by this Section and the burden of proving the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

150) Events Excluded. Unanticipated or increased costs or expenses associated with the performance of NIPSCO's obligations under this Consent Decree shall not constitute a Force Majeure Event.

151) Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and NIPSCO's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; failure of PureAir to agree to modify any contract regarding the operation of the FGD on Bailly Units

7 or 8; Malfunction of a Unit or emission control device; acts of God; acts of war or terrorism; and orders by a government official, government agency, other regulatory authority, or a regional transmission organization, acting under and authorized by applicable law, that directs NIPSCO to supply electricity in response to a system-wide (statewide or regional) emergency or to shut down a Unit or Units. Depending upon the circumstances and NIPSCO's response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of NIPSCO and NIPSCO has taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

152) As part of the resolution of any matter submitted to this Court under Section XVIII (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, Plaintiff and NIPSCO by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by the Court. NIPSCO shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule (provided that NIPSCO shall not be precluded from making a further claim of Force Majeure with regard to meeting any such extended or modified schedule).

XVII. AFFIRMATIVE DEFENSES

153) Affirmative defense as to stipulated penalties for excess emissions occurring during Malfunctions. If any of NIPSCO's Units exceeds a unit-specific 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, or Monthly SO2 Removal Efficiency due to a Malfunction, NIPSCO, bearing the burden of proof, has an affirmative defense to stipulated penalties under this Consent Decree if NIPSCO complies with the reporting requirements of Paragraphs 156, and demonstrates all of the following:

a. the excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond NIPSCO's control;

b. the excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

c. to the maximum extent practicable, the air pollution control equipment and processes were maintained and operated in a manner consistent with good practice for minimizing emissions;

d. repairs were made in an expeditious fashion when NIPSCO knew or should have known that the applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency or Monthly SO2 Removal Efficiency was being or would be exceeded. Off-shift labor and overtime must have been utilized, to the greatest extent practicable, to ensure that such repairs were made as expeditiously as practicable;

e. the amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

f. all possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

g. all emission monitoring systems were kept in operation if at all possible;

h. NIPSCO's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence;

i. the excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

j. NIPSCO properly and promptly notified EPA as required by this Consent Decree.

154) Affirmative Defenses as to stipulated penalties for excess emissions occurring during startup or shutdown. If any of NIPSCO's Units exceed a unit-specific 30-Day or 365-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, or Monthly SO2 Removal Efficiency due to startup or shutdown, NIPSCO, bearing the burden of proof, has an affirmative defense to stipulated penalties under this Consent Decree if NIPSCO complies with the reporting requirements of Paragraphs 156, and demonstrates all of the following:

a. The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful and prudent planning and design;

b. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

c. If the emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

d. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions;

e. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable;

f. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

g. All emission monitoring systems were kept in operation if at all possible;

h. NIPSCO's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and

i. NIPSCO properly and promptly notified EPA as required by this Consent Decree.

155) If excess emissions occur due to a Malfunction during startup and/or shutdown, then those instances shall be treated as other Malfunctions subject to Paragraph 153.

156) NIPSCO shall provide notice to the United States in writing of NIPSCO's intent to assert an affirmative defense as to stipulated penalties for Malfunction, startup, or shutdown in NIPSCO's semi-annual progress reports as required by Paragraph 127(e).

This notice shall be submitted to EPA pursuant to the provisions of Section XXI (Notices). The notice shall contain:

a. The identity of each stack or other emission point where the excess emissions occurred;

b. The magnitude of the excess emissions expressed in the units of the applicable emissions limitation and the operating data and calculations used in determining the magnitude of the excess emissions;

c. The time and duration or expected duration of the excess emissions;

d. The identity of the equipment from which the excess emissions emanated;

e. The nature and cause of the emissions;

f. The steps taken, if the excess emissions were the result of a Malfunction, to remedy the Malfunction and the steps taken or planned to prevent the recurrence of the Malfunctions;

g. The steps that were or are being taken to limit the excess emissions; and

h. If NIPSCO's permit contains procedures governing source operation during periods of startup, shutdown, or Malfunction and the excess emissions resulted from startup, shutdown, or Malfunction, a list of the steps taken to comply with the permit procedures.

157) A Malfunction, startup, or shutdown shall not constitute a Force Majeure Event unless the Malfunction, startup, or shutdown also meets the definition of a Force Majeure Event, as provided in Section XVI (Force Majeure).

XVIII. DISPUTE RESOLUTION

158) The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Party.

159) The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Party advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

160) Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually agreed upon alternative dispute resolution ("ADR") forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

161) If the disputing Parties are unable to reach agreement during the informal negotiation period, Plaintiffs shall provide NIPSCO with a written summary of their

position regarding the dispute. The written position provided by Plaintiffs shall be considered binding unless, within forty-five (45) calendar days thereafter, NIPSCO seeks judicial resolution of the dispute by filing a petition with this Court. Plaintiffs may respond to the petition within forty-five (45) calendar days of filing. In their initial filings with the Court under this Paragraph, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes.

162) The time periods set out in this Section may be shortened or lengthened upon motion to the Court of one of the Parties to the dispute, explaining the Party's basis for seeking such a scheduling modification.

163) This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

164) As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. NIPSCO shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule, provided that NIPSCO shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

XIX. PERMITS AND SIP REVISIONS

165) Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires NIPSCO to secure a permit to authorize construction or operation of any device contemplated herein, including all preconstruction, construction, and operating permits required under state law, NIPSCO shall make such application in a timely manner. EPA and the State of Indiana shall use their best efforts to review expeditiously all permit applications submitted by NIPSCO to meet the requirements of this Consent Decree.

166) Notwithstanding the previous paragraphs, nothing in this Consent Decree shall be construed to require NIPSCO to apply for, amend or obtain (1) a PSD or Nonattainment NSR permit or permit modification for any physical change in, or any change in the method of operation of, any NIPSCO System Unit that would give rise to claims resolved by Section XII (Resolution of Claims) of this Consent Decree; or (2) any Title V Permit or other operating permit or permit modification, or application therefore, related to or arising from any physical change in, or change in the method of operation of, any NIPSCO System Unit that would give rise to claims resolved by Section XII (Resolution of Claims) of this Consent Decree.

167) When permits are required as described in Paragraph 165, NIPSCO shall complete and submit applications for such permits to the appropriate authorities to allow time for all legally required processing and review of the permit request, including requests for additional information by the permitting authorities. Any failure by NIPSCO to submit a timely permit application for NIPSCO System Units shall bar any use by NIPSCO of

Section XVI (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

168) Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term has or will become part of a Title V permit, subject to the terms of Section XXIX (Conditional Termination of Enforcement Under Decree) of this Consent Decree.

169) Within one hundred and eighty (180) days after the Date of Entry of this Consent Decree, NIPSCO shall amend any Title V permit application, or apply for modifications to its Title V permits to include a schedule for implementation of all Annual System Tonnage Limitations, as well as all Unit-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, any required 30- or 365-Day Rolling Average Emission Rate or Removal Efficiency and the requirements pertaining to the Surrender of Allowances. Any modifications to the Title V permits or Title V permit applications pursuant to this Paragraph shall include a provision that recognizes that any noncompliance with Annual System Tonnage Limitation requirements constitutes a single violation for the NIPSCO System as a whole and does not create separate violations for each Unit or each facility within the NIPSCO System.

170) Within one (1) year from the Date of Entry of this Consent Decree, NIPSCO shall submit a written request that IDEM amend the Indiana SIP to incorporate all

of the following Consent Decree requirements: performance, operational, maintenance, and control technology requirements; emission rates; removal efficiencies; system-wide Annual Tonnage Limitations; allowance surrenders; limits on use of emission credits; and operation, maintenance and optimization requirements. Such request shall include not only requirements related to particular Units in the NIPSCO System but also those related to the NIPSCO System as a whole.

171) As soon as practicable, but in no event later than ninety (90) days after the Indiana SIP is amended to include the requirements set forth in Paragraph 170 above, NIPSCO shall file a complete application to IDEM to incorporate the requirements of the Indiana SIP, as amended, into the Title V operating permit for each Facility. In making such an application, NIPSCO shall request that the Title V operating permit for each Facility: (i) refer to the section of the amended Indiana SIP that incorporates the system-wide requirements to comply with the Annual System Tonnage Limitation for NOx in Table 4, and the Annual System Tonnage Limitation for SO_2 in Table 6; and (ii) include a provision that recognizes that any noncompliance with any Annual System Tonnage Limitation constitutes a single violation for the NIPSCO System as a whole and does not create separate violations for each Unit or each facility within the NIPSCO System. The requirement to comply with the system-wide Annual System Tonnage Limitations for NOx and SO_2 shall continue to apply after the termination of the Consent Decree.

172) NIPSCO shall provide Plaintiffs with a copy of its request for SIP amendment (as required in Paragraph 170, above) and its applications for Title V Permit modifications (as required in Paragraph 169 and 171, above), as well as a copy of any

permit proposed as a result of such application, to allow for timely participation in any public comment opportunity.

173) If NIPSCO sells or transfers to an entity unrelated to NIPSCO ("Third Party Purchaser") part or all of its Ownership Interest in the NIPSCO System or individual Units, NIPSCO shall comply with the requirements of Section XXII (Sales or Transfers of Ownership Interests) with regard to such Unit or Units prior to any such sale or transfer unless, following any such sale or transfer, NIPSCO remains the holder of the federally enforceable permit for such facility.

XX. INFORMATION COLLECTION AND RETENTION

174) Any authorized representative of the United States, including its attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the NIPSCO System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by NIPSCO or its representatives, contractors, or consultants; and

d. assessing NIPSCO's compliance with this Consent Decree.

175) NIPSCO shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors' or agents' possession or control, and that directly relate to NIPSCO's performance of its obligations under this Consent Decree for

the following periods: (a) until December 31, 2023, for records concerning physical or operational modifications that are subject to reopener provisions of Section XII, Subsection B of this Consent Decree; and (b) until December 31, 2019, for all other records. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

176) All information and documents submitted by NIPSCO pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of documents unless: (a) the information and documents are subject to legal privileges or protection; or (b) NIPSCO claims and substantiates in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

177) Nothing in this Consent Decree shall limit the authority of the EPA to conduct tests and inspections at NIPSCO's facilities under section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

XXI. NOTICES

178) Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States Department of Justice:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-08417

As to EPA:

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

George Czerniak
Chief, Air Enforcement and Compliance Assurance Branch
EPA Region 5 (AE-17J)
77 West Jackson St.
Chicago, IL 60604

As to the State of Indiana:

Phil Perry
Indiana Department of Environmental Management
Chief, Air Compliance Branch
100 North Senate Avenue
MC-61-53, IGCN 1003
Indianapolis, IN 46204-2251

As to the Northern Indiana Public Service Company:

Vice President, Operations
NIPSCO
801 East 86th Ave.
Merrillville, IN 46410

and

Chief Legal Officer
NiSource, Inc.
801 East 86th Ave.
Merrillville, IN 46410

179) All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or overnight delivery service; or (b) certified or registered mail, return receipt requested. All notifications, communications and transmissions sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked. If sent by overnight delivery service, they shall be deemed submitted on the date they are delivered to the delivery service.

180) Any Party may change the notice recipient, the address for providing notices or the means of transmittal to it by serving the other Party with a notice setting forth such new notice recipient, such new address or such changed means of transmittal (e.g., to electronic format).

XXII. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

181) If NIPSCO proposes to sell or transfer any Ownership Interest in any System Unit to an entity unrelated to NIPSCO ("Third Party Purchaser"), it shall advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to Plaintiffs pursuant to Section XXI (Notices) of this Consent Decree at least sixty (60) days before such proposed sale or transfer.

182) No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and EPA have executed, and the Court has approved, a modification pursuant to Section XXV (Modification) of this Consent Decree making the Third Party Purchaser a party to this Consent Decree and jointly and severally liable with NIPSCO for all the requirements of this Decree that may be applicable to the transferred or purchased Ownership Interests.

183) This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between NIPSCO and any Third Party Purchaser so long as the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation as between NIPSCO and any Third Party Purchaser of Ownership Interests of the burdens of compliance with this Decree, provided that both NIPSCO and such Third Party Purchaser shall remain jointly and severally liable to EPA for the obligations of the Decree applicable to the transferred or purchased Ownership Interests.

184) If EPA agrees, EPA, NIPSCO, and the Third Party Purchaser that has become a party to this Consent Decree, pursuant to Paragraph 182, may execute a modification that relieves NIPSCO of its liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests. Notwithstanding the foregoing, however, NIPSCO may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections X (Environmental Mitigation Projects) and XI (Civil Penalty). NIPSCO may propose and EPA may agree to restrict the scope of the joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the transferred or purchased Ownership Interests, to the extent such obligations may be adequately separated in an enforceable manner.

185) Paragraphs 182 and 184 of this Consent Decree does not apply if an Ownership Interest is sold or transferred solely as collateral security in order to consummate a financing arrangement (not including a sale-leaseback), so long as NIPSCO:

(a) remains the operator (as that term is used and interpreted under the Clean Air Act) of the NIPSCO System Units; (b) remains subject to and liable for all obligations and liabilities of this Consent Decree; and (c) supplies Plaintiffs with the following certification within 30 days of the sale or transfer:

> Certification of Change in Ownership Interest Solely for Purpose of Consummating Financing. We, the Chief Executive Officer and General Counsel of the Northern Indiana Public Service Co., jointly certify under Title 18 U.S.C. section 1001, on our own behalf and on behalf of Northern Indiana Public Service Co. ("NIPSCO"), that any change in NIPSCO's Ownership Interest in any Unit that is caused by the sale or transfer as collateral security of such Ownership Interest in such Unit(s) pursuant to the financing agreement consummated on [insert applicable date] between NIPSCO and [insert applicable entity]: (a) is made solely for the purpose of providing collateral security in order to consummate a financing arrangement; (b) does not impair NIPSCO's ability, legally or otherwise, to comply timely with all terms and provisions of the Consent Decree entered in *United States of America v. Northern Indiana Public Service Co..*, Civil Action No. _____; c) does not affect NIPSCO's operational control of any Unit covered by that Consent Decree in a manner that is inconsistent with NIPSCO's performance of its obligations under the Consent Decree; and d) in no way affects the status of NIPSCO's obligations or liabilities under that Consent Decree.

XXIII. EFFECTIVE DATE

186) The effective date of this Consent Decree shall be the Date of Entry as defined by Paragraph 19. If this Consent Decree is not entered by the Court in the form presented to the Court or the United States or the State of Indiana withhold consent to this Consent Decree before filing, its terms shall be null and void and the Parties shall have no obligation or rights hereunder and the terms of this Consent Decree shall not be used as evidence in any litigation between or among the parties to the Consent Decree.

XXIV. RETENTION OF JURISDICTION

187) The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to

take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXV. MODIFICATION

188) The terms of this Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and NIPSCO. Where the modification constitutes a material change to any term of this Consent Decree, it shall be effective only upon approval by the Court.

XXVI. GENERAL PROVISIONS

189) This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The emission rates set forth herein do not relieve Defendant from any obligation to comply with other state and federal requirements under the Clean Air Act, including Defendant's obligation to satisfy any state modeling requirements set forth in the Indiana State Implementation Plan.

190) This Consent Decree does not apply to any claim(s) of alleged criminal liability.

191) In any subsequent administrative or judicial action initiated by Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Defendant shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by Plaintiffs in the

subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the validity of Section XII (Resolution of Claims).

192) Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Defendant of its obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Sections XII (Resolution of Claims), nothing contained in this Consent Decree shall be construed to prevent or limit the rights of Plaintiffs to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

193) Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Consent Decree, every other term used in this Consent Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Consent Decree what such term means under the Act or those implementing regulations.

194) Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 40 C.F.R. § 52.12(c) (62 Fed. Reg. 8314; Feb. 24, 1997)) concerning the use of data for any purpose under the Act.

195) Each limit and/or other requirement established by or under this Consent Decree is a separate, independent requirement.

196) Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.070

lb/mmBTU is not met if the actual Emission Rate is 0.071 lb/mmBTU. NIPSCO shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending upon whether the limit is expressed to three or two significant digits. For example, if an actual Emission Rate is 0.0704, that shall be reported as 0.070, and shall be in compliance with an Emission Rate of 0.070, and if an actual Emission Rate is 0.0705, that shall be reported as 0.071, and shall not be in compliance with an Emission Rate of 0.070. NIPSCO shall report data to the number of significant digits in which the standard or limit is expressed.

197) This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties.

198) This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supercedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

199) Each Party to this action shall bear its own costs and attorneys' fees.

200) The Parties expressly recognize that whenever this Consent Decree specifies that a 30- Day Rolling Average Emission Rate or a 30-Day Rolling Average Removal Efficiency shall be achieved and/or maintained commencing or starting by or no later than a certain day or date, then compliance with such Rate or Removal Efficiency shall commence immediately upon the date specified, and that compliance as of such

specified date (e.g. December 30) shall be determined based on data from that date and the 29 prior Unit Operating Days (e.g. December 1-29).

201) The Parties expressly recognize that whenever this Consent Decree specifies that a Monthly SO_2 Removal Efficiency shall be achieved and/or maintained at Bailly commencing or starting by or no later than a certain month, then that certain month shall be the first month included in the specified Monthly SO_2 Removal Efficiency (e.g., where the Decree specifies that a 95% Monthly SO_2 Removal Efficiency is to be achieved and maintained no later than January 2011, then January 2011 shall be the first month included in the first Monthly SO_2 Removal Efficiency period, and no day or month prior to January 2011 shall be subject to the Monthly SO_2 Removal Efficiency requirement or included in any calculation to determine compliance with such removal efficiency).

202) The Parties expressly recognize that whenever this Consent Decree specifies that a 365-Day Rolling Average Emission Rate shall be achieved and/or maintained commencing or starting by, on, or no later than a certain day or date, then that certain day or date, if it is an Operating Day, or if it is not an Operating Day then the first Operating Day thereafter, shall be the first day subject to that specified 365-Day Rolling Average Emission Rate (e.g., if the specified 365-Day Rolling Average Emission Rate is to be achieved and maintained from January 1, 2014 through December 31, 2014, and January 1, 2014 is an Operating Day, then January 1, 2014 shall be the first day included in the first 365-Day Rolling Average Emission Rate period, and no day prior to January 1, 2014 shall be subject to that specified 365-Day Rolling Average Emission Rate requirement or included in any calculation to determine compliance with such rate).

XXVII. SIGNATORIES AND SERVICE

203) Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

204) This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

205) Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

206) Unless otherwise ordered by the Court, the Plaintiffs agree that the Defendant will not be required to file any answer or other pleading responsive to the Complaint in this matter until and unless the Court expressly declines to enter this Consent Decree, in which case Defendant shall have no less than thirty (30) days after receiving notice of such express declination to file an answer or other pleading in response to the Complaint.

XXVIII. PUBLIC COMMENT

207) The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. Defendant shall not oppose entry of this

Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States or the State of Indiana has notified Defendant, in writing, that the United States or the State of Indiana no longer supports entry of the Consent Decree.

XXIX. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

208) Termination as to Completed Tasks. As soon as NIPSCO completes a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, NIPSCO may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

209) Conditional Termination of Enforcement Through the Consent Decree. After NIPSCO:

a. has successfully completed construction, and has maintained operation, of all pollution controls as required by this Consent Decree;

b. has obtained final permits and SIP revisions that incorporate the requirements of this Consent Decree, as enforceable permit terms or enforceable SIP terms, of all of the Unit performance and other requirements specified in Section XIX (Permits and SIP Revisions) of this Consent Decree; and

c. certifies that the date is later than December 31, 2018, then NIPSCO may so certify these facts to Plaintiffs and this Court. If Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of NIPSCO's certification, then, for any Consent Decree violations that occur after the filing of notice, Plaintiffs shall pursue enforcement of the requirements contained in the Indiana SIP and Title V permit through the

Signature Page for Consent Decree in:

United States of America
v.
Northern Indiana Public Service Co.

FOR THE UNITED STATES OF AMERICA:

Susan Hedman
Regional Administrator
United States Environmental Protection Agency Region 5

Robert A. Kaplan
Regional Counsel
United Stated Environmental Protection Agency Region 5

Louise C. Gross
Associate Regional Counsel
United States Environmental Protection Agency Region 5

Signature Page for Consent Decree in:

United States of America
v.
Northern Indiana Public Service Co.

FOR THE UNITED STATES OF AMERICA:

Cynthia Giles 1/6/11

Cynthia Giles
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

12/20/10

Phillip A. Brooks
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Seema Kakade

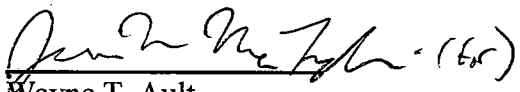
Seema Kakade
Attorney Advisor, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Signature Page for Consent Decree in:

United States of America
v.
Northern Indiana Public Service Co.

FOR THE UNITED STATES OF AMERICA:

David Capp
United States Attorney
Northern District of Indiana



Wayne T. Ault
Assistant United States Attorney
5400 Federal Plaza, Suite 1500
Hammond, Indiana 46320
Phone: 219-937-5500
Facsimile: 219-937-5547
Email: wayne.ault@usdoj.gov

Signature Page for Consent Decree in:

United States of America
v.
Northern Indiana Public Service Co.

FOR THE UNITED STATES OF AMERICA:

Ignacia S. Moreno
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

Jerome W. MacLaughlin
Trial Attorney
Environmental Enforcement Section
Environmental and Natural Resources Division
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20044-7611
Phone: 202-616-7162
Facsimile: 202-616-2427
Email: jerry.maclaughlin@usdoj.gov

Indiana SIP and applicable Title V permit, and not through this Consent Decree.

210) Resort to Enforcement Under this Consent Decree. Notwithstanding Paragraph 209 above, if enforcement of a provision in this Consent Decree cannot be pursued by a party under the Indiana SIP or applicable Title V permit, or if a Consent Decree requirement was intended to be part of the Indiana SIP or the applicable Title V Permit and did not become or remain part of such SIP or permit, then such requirement may be enforced under the terms of this Consent Decree at any time.

XXX. FINAL JUDGMENT

211) Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment among Plaintiffs and NIPSCO.

SO ORDERED, THIS _____ DAY OF _____, 20__.

_____

HONORABLE _____

UNITED STATES DISTRICT COURT JUDGE

Signature Page for Consent Decree in:

United States of America
v.
Northern Indiana Public Service Co.

FOR THE STATE OF INDIANA:

FOR THE STATE OF INDIANA,
ON BEHALF OF THE INDIANA DEPARTMENT OF
ENVIRONMENTAL MANAGEMENT

Thomas W. Easterly
Commissioner
Indiana Department of Environmental Management

As to form and legality:

Gregory F. Zoeller
Indiana Attorney General

Patricia Orloff Erdmann
Chief Counsel for Litigation
Office of the Attorney General
Indiana Government Center South
5th Floor
302 West Washington Street
Indianapolis, Indiana 46204

APPENDIX A: ENVIRONMENTAL MITIGATION PROJECTS

In compliance with and in addition to the requirements in Section XI of this Consent Decree (Environmental Mitigation Projects), NIPSCO shall comply with the requirements of this Appendix to ensure that the benefits of the $9.5 million in federally directed Environmental Mitigation Projects (Projects) are achieved.

I. Overall Environmental Projects Schedule

A. Within the specified time delineated for each Project, as further described below, NIPSCO shall submit proposed Project plan(s) to EPA for review and approval pursuant to Section XIV of the Consent Decree (Review and Approval of Submittals) for expenditure of the Project Dollars specified in this Appendix in accordance with the deadlines established in this Appendix. EPA shall determine, prior to approval, that all Projects are consistent with federal law.

B. Beginning one hundred and twenty (120) days from the Date of Entry, and continuing annually thereafter until completion of each Project (including any applicable periods of demonstration or testing), NIPSCO shall provide EPA with written reports detailing the progress of each Project, including an accounting of Project Dollars spent to date.

C. All proposed Project plans shall include the following:

1. A plan for implementing the Project;
2. A summary-level budget for the Project;
3. A time-line for implementation of the Project; and
4. A description of the anticipated environmental benefits of the Project, including an estimate of emission reductions (e.g., SO_2 , NOx, PM, CO2) expected to be realized.

D. Upon approval by EPA of the plan(s) required by this Appendix, NIPSCO shall complete the approved Project(s) according to the approved plan(s). Nothing in this Consent Decree shall be interpreted to prohibit NIPSCO from completing the Project(s) ahead of schedule.

E. In accordance with the requirements of Paragraph 114, within 60 days following the completion of each Project, NIPSCO shall submit to EPA for approval a report that documents:

1. The date the Project was completed;
2. The results of implementation of the Project, including the estimated emission reductions or other environmental benefits achieved; and
3. The Project Dollars incurred by NIPSCO in implementing the Project.

II. Environmental Mitigation Projects

A. Clean Diesel Retrofit Project

1. Within 120 day of the Date of Entry, NIPSCO shall propose to EPA for review and approval a plan, in consultation with IDEM, to retrofit in-service diesel engines with emission control equipment further described in this Section, designed to reduce emissions of particulates and/or ozone precursors (the "Clean Diesel Retrofit Project") and to fund the operation and maintenance of the retrofit equipment for the time-period described below. The Project shall include, where necessary, techniques and infrastructure needed to support such retrofits. NIPSCO shall ensure, or direct any third party contractor or partner to ensure, that the recipients operate and maintain the retrofit equipment for five years from the date of installation by providing funding for operation and maintenance as described in Section II.A.2.g, below.

2. In addition to the requirements of Section I. C. of this Appendix, the plan shall also satisfy the following criteria:

a. Involve vehicles based in and equipment located in NIPSCO's service territory in northern Indiana, bordered by the cities of Gary-Hammond, Michigan City, South Bend-Elkhart, and Fort Wayne.

b. Provide for the retrofit of public diesel engines with EPA or California Air Resources Board ("CARB") verified emissions control technologies to achieve the greatest reasonably possible mass reductions of particulates and/or ozone precursors for the fleet(s) that participate(s) in the Clean Diesel Retrofit Project. Depending upon the particular EPA or CARB verified emissions control technology selected, the retrofit diesel engines will be expected to achieve emission reductions of particulates and/or ozone precursors by 30%-90%.

c. Describe the process NIPSCO will use to determine the most appropriate emissions control technology for each particular diesel engine that will achieve the greatest reasonably possible mass reduction of particulates and/or ozone precursors. In making this determination, NIPSCO must take into account the particular operating criteria required for the EPA or CARB verified emissions control technology to achieve the verified emissions reductions.

d. Provide for the retrofit of diesel engines with either: (a) diesel particulate filters (DPF); (b) diesel oxidation catalysts (DOC); or (c) closed crankcase ventilation systems with either DPF or DOC.

e. Describe the process NIPSCO will use to notify fleet operators and owners within the geographic area specified in Section II.A.2.a that their fleet of vehicles may be eligible to participate in the Clean Diesel Retrofit Project and to solicit their interest in participating in the Project.

f. Describe the process and criteria NIPSCO will use to select the particular fleet operator and owner to participate in this Project, consistent with the requirements of this Section.

g. For each of the recipient fleet owners and operators, describe the amount of Project Dollars that will cover the costs associated with: (a) purchasing the verified emissions control technology, (b) installation of the verified emissions control technology (including datalogging), (c) training costs associated with repair and maintenance of the verified emissions control technology (including technology cleaning and proper disposal of waste generated from cleaning), and (d) the incremental costs for repair and maintenance of the retrofit equipment (i.e., DPF, DOC, closed crankcase ventilation system) for five years from the date of installation, including the costs associated with the proper disposal of the waste generated from cleaning the verified emissions control technology. This Project shall not include costs for normal repair or operation of the retrofit diesel fleet. Include a mechanism to ensure that recipients of the retrofit equipment will bind themselves to follow the operating criteria required for the verified emissions control technology to achieve the verified emissions reductions and properly maintain the retrofit equipment installed in connection with the Project for the period beginning on the date the installation is complete through December 31, 2015.

h. Describe the process NIPSCO will use for determining which diesel engines in a particular fleet will be retrofitted with the verified emissions control technology, consistent with the criteria specified in Section II.A.2.b.

i. Ensure that recipient fleet owners and/or operators, or their funders, do not otherwise have a legal obligation to reduce emissions through the retrofit of diesel engines.

j. For any third party with whom NIPSCO might contract to carry out this Project, establish minimum standards that include prior experience in arranging retrofits, and a record of prior ability to interest and organize fleets, school districts, and community groups to join a clean diesel program.

k. Direct the recipient fleet(s) to comply with local, state, and federal requirements for the disposal of the waste generated from the verified emissions control technology and follow CARB's guidance for the proper disposal of such waste, provided however, that NIPSCO shall not be a guarantor of or responsible for the actions or omissions of the recipients.

l. Include a schedule and budget for completing each portion of the Project, including funding for operation and maintenance of the retrofit equipment through December 31, 2015.

3. In addition to the information required to be included in the report pursuant to Section I.C, NIPSCO shall also describe the fleet owner/operator; where it implemented this Project; the particular types of verified emissions control technology (and the number of each type) that it installed pursuant to this Project; the type, year, and horsepower of each vehicle; an estimate of the number of citizens affected (if applicable) by this Project, and the basis for this estimate; and an estimate of the emission reductions for Project or engine, as appropriate (using the manufacturer's estimated reductions for the particular verified emissions control technology), including particulates, hydrocarbons, carbon monoxide, and nitrogen oxides.

B. Wood Stove and Wood Outdoor Boiler Changeout Project

1. Within 120 days of the Date of Entry, NIPSCO shall propose a plan to sponsor a Wood-burning Changeout and Retrofit Project ("Wood Stove/Boiler Changeout and Retrofit Project") that a state or local government agency ("air pollution control agency") or third-party non-profit will agree to implement in an area that would benefit from reductions of fine particle pollution and/or hazardous air pollutants by replacing, or retrofitting or upgrading inefficient, higher polluting wood-burning stoves and outdoor boilers with Energy Star qualified Heat Pumps, EPA Phase 2 hydronic heaters, natural gas boilers of 90% or higher AFUE, natural gas furnaces of 92% or higher AFUE or EPA-certified wood-stoves and/or cleaner burning, more energy-efficient hearth appliances (e.g., wood pellet, gas, or propane stove).

2. Any Wood Stove/Boiler Changeout and Retrofit Project that NIPSCO sponsors shall provide educational information (including, energy efficiency, health and safety benefits, and outreach regarding cleaner-burning alternatives and proper operation of the new technology) and incentives through rebates, discounts, or in some instances, actual replacement of the old technology wood-burning stoves or boilers for income-qualified residential homeowners, to encourage residential homeowners to replace their old, higher polluting and less energy efficient wood stoves or outdoor boilers.

3. NIPSCO shall sponsor the implementation of any Wood Stove/Boiler Changeout and Retrofit Project in NIPSCO's service area(s) in northern Indiana, bordered by the cities of Gary-Hammond, Michigan City, South Bend-Elkhart, and Fort Wayne that promise significant environmental benefit from the Wood Stove/Boiler Changeout and Retrofit Project. The Wood Stove/Boiler Changeout and Retrofit Project shall also include the counties of LaPorte, Lake, and Porter. In determining the specific areas to implement this Project within the aforementioned geographic area, NIPSCO shall give priority to areas with high amounts of air pollution, especially particle pollution and/or hazardous air pollutants, areas located within a geography and topography that makes it susceptible to high levels of particle pollution, or areas that have a significant number of old and/or higher polluting wood-burning stoves or outdoor boilers.

4. The air pollution control agency(ies) and/or non-profit(s) that NIPSCO selects shall consult with EPA's wood smoke team and implement any Wood Stove/Boiler Changeout and Retrofit Project consistent with the materials available on EPA's Burn

Wise website at http://www.epa.gov/burnwise.

5. In addition to the requirements of Section I.C , any plan to implement this Project shall also satisfy the following criteria:

a. Identify the air pollution control agency(ies) and/or non-profit(s) selected to implement the Wood Stove/Boiler Changeout and Retrofit Project.

b. Describe the schedule and budgetary increments in which NIPSCO shall provide the necessary funding to the air pollution control agency(ies) and/or non-profits(s) to implement any Wood Stove/Boiler Changeout and Retrofit Project.

c. Ensure that the air pollution control agency(ies) and/or non-profit(s) will implement any Wood Stove/Boiler Changeout and Retrofit Project in accordance with the requirements of this Appendix, and that the Project Dollars will be used to support the actual replacement, upgrade or retrofit of stoves/boilers currently used as the primary or secondary source of residential heat with a cleaner, more energy efficient stove/boiler (i.e., geothermal heat pump, wood pellet stove, EPA-certified wood stove, gas stove, EPA Phase 2 qualified hydronic heater, natural gas boiler of 90% or higher AFUE, natural gas furnace of 92% or higher AFUE or propane stove). To enable the project to carry on in the future, funds may be used to support changeout/upgrades through revolving loan programs or other low-interest loan programs. NIPSCO shall limit the use of Project Dollars for administrative costs associated with implementation of the program to no greater than 10% of the Project Dollars NIPSCO provides to a specific air pollution control agency and/or non-profit. Up to 7% can be used for personnel cost and the remaining 3 % for other (e.g., outreach materials, training, studies/surveys, travel) project support costs.

d. Describe all of the elements of any Wood Stove/Boiler Changeout and Retrofit Project that the air pollution control agency(ies) and/or nonprofit(s) will implement. NIPSCO shall describe and estimate the number of energy efficient appliances it intends to make available, the cost per unit, and the criteria the air pollution control agency(ies) and/or nonprofit(s) will use to determine which residential homeowners should be eligible for actual stove replacement.

e. If applicable, identify any organizations with which the air pollution control agency(ies) and/or non-profit(s) will partner to implement the Project, including such organizations as: the Hearth, Patio, and Barbecue Association of America, the Chimney Safety Institute of America, a local chapter of the American Lung Association, individual stove retailers, propane dealers, facilities that will dispose of old stoves so that they cannot be resold or reused, housing assistance agencies, local fire departments, local health organizations, and local green energy organizations.

f. Describe how the air pollution control agency(ies) and/or non-profit(s) will ensure that the old and/or higher polluting wood-burningstove/boiler will be properly recycled or disposed.

C. Land Acquisition and Restoration Project in Northwest Indiana

1. Within 45 days from the Date of Entry, NIPSCO shall establish a stakeholder process to solicit input into the funding of land acquisition or restoration Project(s) of lands adjacent to, or near, the Indiana Dunes National Lakeshore, and may include other lands in the northwest Indiana area, potentially affected by emissions form one or more of the NIPSCO Units. The stakeholder process will consist of a maximum of five members and, at minimum, shall include a representative from The Indiana Dunes National Lakeshore, a representative from Indiana Department of Natural Resources, and a representative from an environmental organization such as the Nature Conservancy.

2. The goal of this Project will be the protection through acquisition and/or restoration of ecologically significant land, watersheds, vegetation, and forests within northwest Indiana using adaptive management techniques designed to improve ecosystem health and mitigate harmful effects from air pollution. For purposes of this Appendix and Section XI of this Consent Decree (Environmental Mitigation Projects), land acquisition means purchase or transfer of interests in land, including fee ownership, easements, or other restrictions that run with the land that provide for perpetual protection of the acquired land. The transfer of property or land interests by NIPSCO to any governmental or nongovernmental organization shall be credited at fair market value and must provide for perpetual protection of the land. Restoration may include, by way of illustration, direct reforestation (particularly of tree species that may be affected by acidic deposition) and soil enhancement. Any restoration action must also incorporate the acquisition of an interest in the restored lands sufficient to ensure perpetual protection of the restored land, unless the land restored is already under the ownership of a governmental entity that has a legal duty to conserve the land in perpetuity. Any proposal for acquisition of land must identify fully all owners of the interests in the land. Every proposal for acquisition or transfer of land must identify the ultimate holder of the interests to be acquired and provide a basis for concluding that the proposed holder of title is appropriate for long-term protection of the ecological and/or environmental benefits sought to be achieved through the acquisition.

3. The Project(s) will focus on lands adjacent to, or near, the Indiana Dunes National Lakeshore, and may include other lands in the northwest Indiana area, potentially affected by emissions from one or more of the NIPSCO Units. Examples of Projects include:

a. Acquire and Restore Disturbed Land at NIPSCO Michigan City Plant and Crescent Dune Area: Funding this Project would provide for acquisition, cleanup, invasive species control, and restoration of approximately 246 acres at and around the NIPSCO Michigan City site; and

b. Acquire, Restore, and Donate Land Adjacent to Indiana Dunes National Lakeshore: Funding for this Project would provide for acquisition and restoration of lands adjacent to the National Lakeshore and would include the transfer of title to such lands, or the granting of an easement over such lands, to the National Park Service.

4. Within one year of Date of Entry of this Consent Decree, through the stakeholder process described in II.C.1 above, NIPSCO will identify and provide recommendations for specific Projects to EPA for approval.

D. Funding Obligations for Section II Environmental Projects

1. Within three years of the Date of Entry of this Consent Decree, NIPSCO will have completed the expenditure of a minimum of $3,500,000 to fund and implement the approved Clean Diesel and Wood Stove Changeout Projects as described in II.A and II.B. NIPSCO shall retain the discretion to determine how best to allocate the minimum $3,500,000 in Project Dollars between the approved Clean Diesel and Wood Stove Changeout Projects.

2. Within three years of the Date of Entry of this Consent Decree, NIPSCO will have completed the expenditure of a minimum of $1,500,000 and a maximum of $2,000,000 to fund and implement the approved Land Acquisition and Restoration Project as described in II.C.

III. Additional Environmental Mitigation Projects

A. Within 1 year of the Date of Entry, as further described below, NIPSCO shall submit proposed Project plan(s) to EPA for review and approval pursuant to Section XIV of the Consent Decree (Review and Approval of Submittals) for expenditure of the remaining Project Dollars over a period of not more than five years from the Date of Entry, except as provided below. NIPSCO shall not spend more than $2 million of the remaining Project Dollars on a single project in this Section III "Additional Environmental Mitigation Projects." The Parties agree, subject to the requirements of this Appendix, that NIPSCO may in its discretion decide which of the Projects specified in Sections III.C, and D, of this Appendix to propose for EPA approval. NIPSCO may, at its election, consolidate the plans required by this Appendix into a single plan. In addition, NIPSCO may propose during the five year period to make amendments or modifications to the plan or plans for EPA review and approval. NIPSCO has no current obligation to undertake any of the Projects described below in Sections III.C, D, and E.

B. The Parties agree that NIPSCO is entitled to spread its payments for Projects over the five-year period commencing upon the Date of Entry. NIPSCO is not, however, precluded from accelerating payments to better effectuate a proposed mitigation plan, provided that NIPSCO shall not be entitled to any reduction in the nominal amount of the required payments by virtue of the early expenditures. EPA shall determine prior to approval that all Projects are consistent with federal law.

C. Hybrid Fleet Project

1. NIPSCO may elect to submit a plan for a hybrid and/or electric fleet project to reduce emissions from NIPSCO's fleet of motor vehicles. NIPSCO has a substantial fleet of motor vehicles where it operates. These motor vehicles are generally powered by conventional diesel or gasoline engines and include vehicles such as diesel "bucket" trucks. The use of hybrid engine technologies in NIPSCO's motor vehicles, such as diesel-electric engines, will improve fuel efficiency and reduce emissions of NO_X, PM, VOCs, and other air pollutants.

2. As part of any plan for the Hybrid Fleet Project, assuming that NIPSCO elects to undertake this Project, NIPSCO may elect to spend Project Dollars on the replacement of conventional motor vehicles in its fleet with newly manufactured hybrid and/or electric vehicles.

3. In addition to the requirements of Section I.C of this Appendix, any plan for the Hybrid Fleet Project shall:

a. Propose the replacement of convention diesel engines in bucket trucks or other mobile sources with hybrid or electric engines, and/or propose the replacement of portions of NIPSCO's fleet (including cars, vans, and pickup trucks) with hybrid and/or electric vehicles. For purposes of this subsection of this Appendix, "hybrid and/or electric vehicle" means a vehicle that can generate and/or utilize electric power to reduce the vehicles consumption of diesel or gasoline fuel. Any such vehicle proposed for inclusion in the Hybrid Fleet Project shall meet all applicable engine standards, certifications, and/or verifications.

b. Propose a method to account for the amount of Project Dollars that will be credited for each replacement made under subparagraph (a) above, taking into account the incremental cost of such engines or vehicles as compared to conventional engines or vehicles and potential savings associated with the replacement;

c. Prioritize the replacement of diesel-powered vehicles in NIPSCO's fleet. Certify that NIPSCO will use the Hybrid Vehicles for their useful life (as defined in the proposed Plan).

4. Notwithstanding any other provision of this Consent Decree, including this Appendix, NIPSCO shall only receive credit toward Project Dollars for the incremental cost of hybrid and/or electric vehicles as compared to the cost of a newly manufactured, similar motor vehicle powered by conventional diesel or gasoline engines.

D. Electric Vehicle Infrastructure Enhancement

1. NIPSCO may undertake enhancements to the electric vehicle charging infrastructure by funding creation of one or more charging stations for electric vehicles in the Northwest Indiana area bordered by the cities of Gary-Hammond, Michigan City, South Bend-Elkhart, and Fort Wayne. Battery powered and some hybrid vehicles need plug-in infrastructure to recharge the batteries. Establishment of electric vehicle charging stations in Northwest Indiana could expand the useful driving range of electric vehicles in the Chicago metropolitan area as well as encourage Northwest Indiana drivers to purchase electric vehicles for local use as well as commutes to Chicago. Locations for such charging stations would be targeted for areas where vehicles could be left for several hours to fully charge the electric vehicle's battery system.

2. If NIPSCO elects to undertake this Project, it may partner with third party organizations (e.g., NIRPC, SSCC) to handle funding and selection of locations in Northwest Indiana. Locations would be sought to maximize the number of vehicles that could utilize the chargers while striving to expand into Northwest Indiana the network of electric vehicle charging stations currently in the Illinois portion of the greater Chicago metropolitan area. Potential sites could consist of locations that provide public access, including parking lots at mass transit terminals/stops (such as South Shore Commuter Rail stations, RDA bus stops), large industrial facilities or similar employers (NIPSCO, Methodist Hospital, steel mills), residences, and and shopping malls in Lake and Porter counties.

3. Emission reductions - overall emissions reductions would depend upon the number of vehicles utilizing the facilities and would be based upon the type of vehicle the electric vehicle replaces in the general geographic area, the emissions characteristics and the annual vehicle miles traveled (VMT). For the term of this project NIPSCO would commit to effectively supply the vehicle charging station with zero emission renewable energy sources through the use of renewable energy credits (RECs). Therefore the usage would be considered emission free. NIPSCO will report the expected and achieved environmental benefits.

4. NIPSCO may consider and implement additional options to enhance electric vehicle usage, such as to:

a. Provide a purchase incentive for acquisition of plug-in hybrid electric vehicle (PHEV), pure battery electric vehicle (EV), or lesser incentive to a conventional vehicle converted to a plug-in

b. Fund low-interest loans through banks and dealers for plug-in vehicles

c. Provide direct cash incentives to consumers for vehicle purchase.

E. Residential and Commercial Electric to Natural Gas Conversion Project

1. NIPSCO may submit a plan to EPA to implement a Residential and Commercial Electric to Natural Gas Conversion Project ("Conversion Project") to reduce life cycle SO_2, NOx, and PM and other air emissions resulting from residential and commercial space and water heating energy usage. If NIPSCO elects to perform this Conversion Project, the Conversion Project will consist of specific measures that will produce long-term, permanent, environmental benefits by the removal and replacement of electric resistance furnaces and water heaters with new high efficiency natural gas furnaces (92% or higher AFUE) and natural gas water heaters. The reduction in emissions of SO_2 , NOx, PM, and other air emissions would occur based on the more efficient energy delivery by natural gas compared to electricity (approximately 92% delivery efficiency for natural gas versus 32% delivery efficiency for electricity) and the use of inherently cleaner burning natural gas compared to the overall predominance of coal based fuels in this subregion. The Conversion Project will be performed in and demonstrate SO_2 , NOx, PM and other air emission benefits to communities in northern Indiana, bordered by the cities of Gary-Hammond, Michigan City, South Bend-Elkhart, and Fort Wayne area and provide benefits beyond what is required of NIPSCO under any Indiana Utility Regulatory Commission state-wide mandate.

2. If NIPSCO elects to undertake this Conversion Project, it may partner with third party organizations to handle funding and selection of residences and commercial establishments for the removal of electric resistance furnaces and water heaters and replacement with natural gas-fired units.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Kelly r Carmichael
NIPSCO – Schahfer Generating Station
801 E 86th Avenue
Merrillville, IN 46410

DATE: December 28, 2012

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

SUBJECT: Final Decision
Part 70 Operating Permit Renewal
073-29983-00008

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:
Philip W Pack – Senior Vice President – Generation, Interim
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 11/30/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.

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Governor

Thomas W. Easterly
Commissioner

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

TO: Interested Parties / Applicant

DATE: December 28, 2012

RE: NIPSCO – Schahfer Generating Station / 073-29983-00008

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

In order to conserve paper and reduce postage costs, IDEM's Office of Air Quality is now sending many permit decisions on CDs in Adobe PDF format. The enclosed CD contains information regarding the company named above.

This permit is also available on the IDEM website at:
http://www.in.gov/ai/appfiles/idem-caats/

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

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

Please Note: *If you feel you have received this information in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV.*

Enclosures
CD Memo.dot 11/14/08

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.

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Commissioner

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

December 28, 2012

TO: Wheatfield Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: NIPSCO – Schahfer Generating Station
Permit Number: 073-29983-00008

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library.dot 11/30/07

Mail Code 61-53

IDEM Staff	GHOTOPP 12/28/2012 NIPSCO - R.M. Schahfer Generating Station 073-29983-00008 Final			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Kelly R Carmichael NIPSCO - R.M. Schahfer Generating Station 801 E 86th Ave Merrillville IN 46410 (Source CAATS) via confirmed delivery									
2		Phillip W Pack Sr VP - Generation, Interim NIPSCO - R.M. Schahfer Generating Station 801 E 86th Ave Merrillville IN 46410 *(RO CAATS)*									
3		Ms. Lana Gawronski 9296 N 900 W Demotte IN 46310 *(Affected Party)*									
4		Ms. Lorraine Frantz P.O. Box 669 Demotte IN 46310 *(Affected Party)*									
5		Steven & Vickie Stemper ATS Plumbing 974 N. 900 W. Demotte IN 46310 *(Affected Party)*									
6		David & Bonnie Stone 7571 W 100 N Demotte IN 46310 *(Affected Party)*									
7		Mr. Aaron Webster 7149 W 1000 N Demotte IN 46310 *(Affected Party)*									
8		The Echterling Residence 9180 W 950 N Demotte IN 46310 *(Affected Party)*									
9		Mr. Rudolph Nichols United Steelworkers of America Subdistrict 4 113 E. Washington St. Plymouth IN 46563 *(Affected Party)*									
10		Mr. Lawrence A. Vanore Sommer & Barnard Ackerson 1 Indiana Sq Ste 3500 Indianapolis IN 46204-5198 *(Affected Party)*									
11		State Representative District 16 P.O. Box 1 Rensselaer IN 47978 *(Legislator)*									
12		Mr. Gary Dobson 4666 N 250 E Rensselaer IN 47978 *(Affected Party)*									
13		Ms. Melissa Laughlin Rensselar Republican 117 N. Van Rensselaer St, P.O. Box 298 Rensselaer IN 47978 (Affected Party)									
14		Jasper County Commissioners 115 W. Washington Street Rensselaer IN 47978 *(Local Official)*									
15		Jasper County Health Department 105 W. Kellner St Rensselaer IN 47978-2623 *(Health Department)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.
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Mail Code 61-53

IDEM Staff	GHOTOPP 12/28/2012 NIPSCO - R.M. Schahfer Generating Station 073-29983-00008 Final			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Donald Speacht, Jr. 11751 N. County Rd. 500 E. San Pierre IN 46374 (Affected Party)									
2		Donald & Deborah Flour 103 E. Wee Saw Trail Valparaiso IN 46383-8910 *(Affected Party)*									
3		The Banks Family 11846 N CR 100 E Wheatfield IN 46392 *(Affected Party)*									
4		Ms. Kay Asher 4036 Heritage Dr N Wheatfield IN 46392 *(Affected Party)*									
5		Ms. Maryann Desalvo 10145 N 200 E Wheatfield IN 46392 *(Affected Party)*									
6		Victor & Cleone Downing 1333 E 1225 N Wheatfield IN 46392 *(Affected Party)*									
7		Ms. Deborah Conley P.O. Box 307 Wheatfield IN 46392 *(Affected Party)*									
8		Mr. James Gourko P.O. Box 424 Wheatfield IN 46392 *(Affected Party)*									
9		Mr. Scott Helton P.O. Box 307 Wheatfield IN 46392 *(Affected Party)*									
10		Mr. Bob Hetrick 10274 N 200 E Wheatfield IN 46392 *(Affected Party)*									
11		Ms. Monica Jones 9250 N 100 W Wheatfield IN 46392 *(Affected Party)*									
12		Joe & Betty Starewich 4096 N 400 E Wheatfield IN 46392 *(Affected Party)*									
13		Michael & Kathleen Teiron 4073 E 425 N Wheatfield IN 46392 (Affected Party)									
14		Robert & Barbara Witvoet 14240 N State Rd 49 Wheatfield IN 46392 *(Affected Party)*									
15		Sharon Williams 9610 N. 250 E. Wheatfield IN 46392 *(Affected Party)*									

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1		Darlene & Scott Holmes 9161 N 900 W Demotte IN 46310 (Affected Party)									
2		Mr. Kenny Haun P.O. Box 280 Rensselaer IN 47978 *(Affected Party)*									
3		Wheatfield Public Library 350 S Bierma Wheatfield IN 46392 *(Library)*									
4		Tom & Gail Clark 1186 E CR 1250 N Wheatfield IN 46392 *(Affected Party)*									
5		Mike & Vicki Drzik 11664 N 80 W Wheatfield IN 46392 *(Affected Party)*									
6		Ms. Sheila Estrada 466 E Robbins Wheatfield IN 46392 *(Affected Party)*									
7		Wheatfield Town Council 170 S Grace Street Wheatfield IN 46392 *(Local Official)*									
8		Tom Anderson Save the Dunes 444 Barker Rd Michigan City IN 46360 *(Affected Party)*									
9											
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