IDEM

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

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

NOTICE OF 30-DAY PERIOD FOR PUBLIC COMMENT

Preliminary Findings Regarding a Signficant Modification to a Part 70 Operating Permit

for Indianapolis Power & Light Company - Harding Street Station in Marion County

Significant Source Modification No.: 097-35518-00033 and Significant Permit Modification No.: 097-35534-00033

The Indiana Department of Environmental Management (IDEM) has received an application from Indianapolis Power & Light Company - Harding Street Station, located at 3700 & 4190 S. Harding Street, Indianapolis, IN 46217, for a significant modification of its Part 70 Operating Permit issued on August 11, 2011. If approved by IDEM's Office of Air Quality (OAQ), this proposed modification would allow Indianapolis Power & Light Company - Harding Street Station to make certain changes at its existing source. Indianapolis Power & Light Company - Harding Street Station has applied to modify Boiler 70 (Unit 7) to enable the unit to use natural gas as its only fuel and discontinue the use of coal and fuel oil. The source is now proposing to install a new 100 MMBtu per hour gas fired auxiliary boiler instead of the 92 MMBtu/hr natural gas fired auxiliary boiler that was originally public noticed. On July 22, 2015, IDEM public noticed Permit Nos SSM 097-35518-00033 and SPM 097-35534-00033 for IPL - Harding for a 92 MMBtu/hr natural gas-fired auxiliry boiler. The change is to this permit is an increase the rated capacity of the auxiliary boiler from 92 MMBtu/hr to 100 MMBtu/hr.

The applicant intends to construct and operate new equipment that will emit air pollutants; therefore, the permit contains new or different permit conditions. In addition, some conditions from previously issued permits/approvals have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes (e.g. changes that add or modify synthetic minor emission limits). IDEM has reviewed this application and has developed preliminary findings, consisting of a draft permit and several supporting documents, which would allow the applicant to make this change.

A copy of the permit application and IDEM's preliminary findings are available at:

> Indianapolis -Marion County Public Library - Central Library
> One Library Square, 40 E. St. Clair Street
> Indianapolis IN 46204

A copy of the preliminary findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

How can you participate in this process?

The date that this notice is published in a newspaper marks the beginning of a 30-day public comment period. If the 30th day of the comment period falls on a day when IDEM offices are closed for business, all comments must be postmarked or delivered in person on the next business day that IDEM is open.

You may request that IDEM hold a public hearing about this draft permit. If adverse comments concerning the **air pollution impact** of this draft permit are received, with a request for a public hearing, IDEM will decide whether or not to hold a public hearing. IDEM could also decide to hold a public meeting instead of, or in addition to, a public hearing. If a public hearing or meeting is held, IDEM will make a separate announcement of the date, time, and location of that hearing or meeting. At a hearing, you would have an opportunity to submit written comments and make verbal comments. At a meeting, you would have an opportunity to submit written comments, ask questions, and discuss any air pollution concerns with IDEM staff.

Comments and supporting documentation, or a request for a public hearing should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM's mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number SSM 097-35518-00033 and SPM 097-35534-00033 in all correspondence.

Comments should be sent to:

Josiah Balogun
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for extension 4-5257
Or dial directly: (317) 234-5257
Fax: (317) 232-6749 attn: Josiah Balogun
E-mail:jbalogun@idem.IN.gov

All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have legal authority to regulate zoning, odor, or noise. For such issues, please contact your local officials.

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM's response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM's decision, if you disagree with that decision. The final decision will also be available on the Internet at the address indicated above, at the local library indicated above, and the IDEM public file room on the 12th floor of the Indiana Government Center North, 100 N. Senate Avenue, Indianapolis, Indiana 46204-2251.

If you have any questions, please contact Josiah Balogun of my staff at the above address.

Tripurari Sinha

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

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DRAFT

Jennifer Hatfield
Indianapolis Power & Light Company - Harding Street Station
3700 S. Harding Street
Indianapolis, IN, 46217

Re: 097-35518-00033
Significant Source Modification

Dear Ms. Hatfield:

Indianapolis Power & Light Company - Harding Street Station was Part 70 Operating Permit Renewal No. 097-29749-00033 on August 11, 2011 for a stationary utility electric generating station located at 3700 & 4190 S. Harding Street, Indianapolis, IN. An application to modify the source was received onFebruary 26, 2015. Pursuant to the provisions of 326 IAC 2-7-10.5, a Significant Source Modification is hereby approved as described in the attached Technical Support Document.

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

(a) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(b) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

The following construction conditions are applicable to the proposed modification:

General Construction Conditions

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

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

Effective Date of the Permit

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

Commenced Construction

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

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

Approval to Construct

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

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

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

A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5.

If you have any questions on this matter, please contact Josiah Balogun of my staff, OAQ, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Josiah Balogun or extension 4-5257 or dial (317) 234-5257.

Sincerely,

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

Attachments: Significant Source Modification and Technical Support Document

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

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Significant Source Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

Indianapolis Power & Light Company - Harding Street Station.
3700 & 4190 S. Harding St.
Indianapolis, Indiana 46217

(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.

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

Significant Source Modification No.: 097-35518-00033	
Issued by: Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date:

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SECTION A SOURCE SUMMARY

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

A.1 General Information [326 IAC 2-7-4(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:	3700 & 4190 S. Harding St., Indianapolis, Indiana 46217
General Source Phone Number:	(317) 261-2006
SIC Code:	4911
County Location:	Marion
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Rule 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(14)]

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

Before Conversion of Boiler number 50 to Natural Gas

(a) One (1) Combustion Engineering Boiler number 50 (also referred to as Unit 5). Boiler 50 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 50. Installation date for Boiler 50 is 1958.

After Conversion of Boiler number 50 to Natural Gas

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 (also referred to as Unit 5), constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

Before Conversion of Boiler number 60 to Natural Gas

(b) One (1) Combustion Engineering Boiler number 60 (also referred to as Unit 6). Boiler 60 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 60. Installation date for Boiler 60 is 1961.

After Conversion of Boiler number 60 to Natural Gas

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 (also referred to as Unit 6), constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 (also referred to as Unit 7). Boiler 70 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Boiler 70 is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, Boiler 70 exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of Boiler 70. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler number 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(d) One (1) Cooling Tower associated with Boiler 70, identified as CT-7, approved for construction in 2012, with a capacity of 189,280 gallons circulating water per minute and maximum drift rate of 0.001%.

(e) One (1) General Electric Gas Turbine Engine number GT1 identified as Unit GT1. Unit GT1 is a distillate oil fired unit with a design heat input capacity rated at 299.0 million Btu per hour and exhausting at Stack/Vent ID GT1-1. Model number MS 5000. Equipped with no add on air pollution control equipment. Installation date for Unit GT1 is 1973.

(f) One (1) General Electric Gas Turbine Engine number GT2 identified as Unit GT2. Unit GT2 is a distillate oil fired unit with a design heat input capacity rated at 299.0 million Btu per hour and exhausting at Stack/Vent ID GT2-1. Model number MS 5000. Equipped with no add on air pollution control equipment. Installation date for Unit GT2 is 1973.

(g) One (1) General Electric Gas Turbine Engine number GT4 identified as Unit GT4. Unit GT4 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 875.0 million Btu per hour and exhausting at Stack/Vent ID GT4-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT4 is 1994.

(h) One (1) General Electric Gas Turbine Engine number GT5 identified as Unit GT5. Unit GT5 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 867.0 million Btu per hour and exhausting at Stack/Vent ID GT5-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT5 is 1995.

(i) One (1) General Electric Gas Turbine Model number PG7241 identified as Unit GT6. Unit GT6 is a natural gas fired unit with a design heat input capacity rated at 1,660 MMBtu per hour and exhausting at Stack/Vent ID GT-6. NOX emissions will be controlled by dry low NOX burners. Installation date for Unit GT6 is 2002.

(j) One (1) General Motors Reciprocating Internal Combustion Standby/Emergency Generator identified as Unit ST14. As an emergency generator, Unit ST14 will be operated less than 500 hours per year. Unit ST14 is distillate oil fired with a design heat input of 27.6 million Btu per hour. Equipped with no add on air pollution control equipment. Exhausting at Stack/Vent ID ST14-1. Installation date for Unit ST14 is 1967.

(k) Coal material handling and storage system with a maximum annual capacity of 7.5 million tons per year and described as follows:

(1) One (1) crusher house, consisting of the following equipment:
(i) Two (2) crushers constructed in 1958;
(ii) One (1) self cleaning static grizzly constructed in 1996; and
(iii) One (1) self cleaning static grizzly constructed in 2006.

(2) One (1) covered conveyor system, constructed in 1931, consisting of the following equipment:
(i) No. 2 conveyor which transfers coal from the railcar receiving area to the crusher house;
(ii) No. 3 conveyor transfers coal from the crusher to No. 4 conveyor;
(iii) No. 4 conveyor transfers coal from the crusher to the cross-over conveyor;
(iv) Cross-over conveyor transfers coal from No. 4 conveyor to No. 5 conveyor or to conveyor 705 (which then transfers to conveyor 703 and to Unit 7); and
(v) No. 5 conveyor transfers coal from the cross-over conveyor to Boiler 50 or Boiler 60.

(3) One (1) covered conveyor system, constructed in 1958 and consisting of the following equipment:
(i) Conveyors identified as 600A, 600B, 601, 602, 605, and 606. 600A and 600B conveyor transfers coal from the railcar receiving area to 601 and 602 conveyors which transfer coal to the crusher house; and
(ii) 605 conveyor transfers coal to 606 or 703 conveyors. 605 and 606 conveyors are located inside the building and transfer coal to five (5) conveyors which transfer coal to Unit 5's and Unit 6's coal bunkers.

(4) One (1) covered conveyor system which became commercial in 1973 and consists of the following equipment:
(i) Conveyors identified as 701 and 702 transfer coal to either the crusher house or the low sulfur coal pile; and
(ii) Conveyors identified as 703 and 704 are the conveyors which transfer coal from 601, 602, and 605 conveyors to Unit 7's coal bunkers.

(5) One (1) covered conveyor system, constructed in 2006 and consisting of the following equipment:
(i) Conveyors identified as 801 and 802 transfer coal to the outside high sulfur coal storage pile.

(6) One (1) covered conveyor system, constructed in 2006 and consists of the following equipment subject to 40 CFR Part 60, Subpart Y;
(i) Conveyors identified as 803 and 804 transfer coal from the high sulfur storage pile to the crusher house.

(l) Limestone transfer from trucks and loader vehicles to the conveyor system, identified as T-1, with a maximum capacity to transfer 230,000 tons of limestone per year and using no control. Constructed in 2006.

(m) Five (5) covered limestone conveyors, identified as T-2, with a maximum capacity to convey 230,000 tons of limestone per year and using no control. Constructed in 2006. Under 40 CFR 60.670, Subpart OOO, T-2 is considered an affected facility.

(n) Two (2) 630 ton capacity limestone storage silos, identified as L7-1 and L7-2, using bin vents LC7-1 and LC7-2 as control, and exhausting to stack/vent LSV7-1 and LSV7-2. Maximum throughput of 230,000 tons of limestone per year. Constructed in 2006. Under 40 CFR 60.670, Subpart OOO, L7-1 and L7-2 are each considered an affected facility.

(o) Two (2) weigh feeders which transfer limestone from the silos to the two (2) enclosed wet ball mills (grinding mills) for grinding limestone, identified as BM7-1 and BM7-2. The ball mill grinding mills are located in a covered building. Constructed in 2006. Under 40 CFR 60.670, Subpart OOO, BM7-1 and BM7-2 are each considered an affected facility.

(p) Gypsum transfer, identified as T-3, with a maximum capacity to transfer 414,000 tons of gypsum per year and using no control. Constructed in 2006.

(q) Six (6) covered gypsum conveyors, identified as T-4, with a maximum capacity to convey 414,000 tons of gypsum and using no control. Constructed in 2006.

(r) One (1) Reciprocating Internal Combustion Engine identified as Unit BSE-2. Unit BSE-2 is a black start diesel-fired engine and not an emergency use engine. Unit BSE-2 has a design heat input of 6.65 million Btu per hour (475 horsepower) and exhausts to Stack/Vent GT2-1. Unit BSE-2 was installed in 1973.

(s) One (1) Reciprocating Internal Combustion Engine identified as Unit BSE-3. Unit BSE-3 is a black start diesel-fired engine and not an emergency use engine. Unit BSE-3 has a design heat input of 6.65 million Btu per hour (475 horsepower) and exhausts to Stack/Vent GT3-1. Unit BSE-3 was installed in 1973.

(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with maximum capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

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) Fuel oil fired combustion sources with heat input equal to or less than two (2) million Btu per hour and firing fuel containing less than five-tenths (0.5) percent sulfur by weight. [326 IAC 6.5-1-2(a)]

(b) Gasoline generators not exceeding 110 horsepower. [326 IAC 6.5-1-2(a)]

(c) Two (2) flyash silos identified as Unit 5/6 Flyash Silo and Unit 7 Flyash Silo for truck loading. Each silo is exhausted to a baghouse. [326 IAC 6.5-1-2(a)]

(d) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2]

(e) One (1) 81 horsepower diesel fired emergency generator identified as Emission Unit ID Generator # 1, installed in 1988, associated with a communication transmitter tower located at 4190 S. Harding Street, Indianapolis, Indiana, 46217. [326 IAC 6.5-1-2(a)]

(f) Grit blast existing steel stack liner [326 IAC 6.5-1-2(a)]

(g) Primer existing steel stack liner with HVLP spray technology [326 IAC 6.5-1-2(a)]

(h) One (1) emergency internal combustion engine used to power a fire pump, identified as FP-1, installed in 1993, with a maximum heat input capacity of 0.56 MMBtu/hr and a rating of 215 horsepower (bhp).

(i) One (1) ponded ash screening operation and associated ash handling, identified as PAS-1, approved for construction in 2013, with a maximum throughput of 200 tons/hr.

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]

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

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

(a) This permit, T097-29749-00033, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

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

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

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

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

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

B.4 Enforceability [326 IAC 2-7-7] [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.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(35), 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(35).

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 April 15 of each year to:

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

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(35).

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(35).

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(35).

(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(35).

(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 T097-29749-00033 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

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

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

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

B.15 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(35).

(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(35).

Request for renewal shall be submitted to:

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

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

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

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

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

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

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

(b) 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(35).

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

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

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

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

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) 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) or (c). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(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(35).

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

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

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

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

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

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

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

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

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

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

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

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

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality

100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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(35).

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

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

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

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

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

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 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 thirty percent (30%) 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.2 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.3 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.4 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.5 Fugitive Particulate Matter Emission Limitations [326 IAC 6-5]

Pursuant to 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations), fugitive particulate matter emissions shall be controlled according to the plan submitted on March 20, 2007. The plan is included as Attachment C.

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

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

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

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:

(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or

(2) If there is a change in the following:

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(2).

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

All required notifications shall be submitted to:

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

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(e) Procedures for Asbestos Emission Control
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).

(g) Indiana Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

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

C.8 Performance Testing [326 IAC 3-6]

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality

100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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

(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(35).

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

Compliance Requirements [326 IAC 2-1.1-11]

C.9 Compliance Requirements [326 IAC 2-1.1-11]

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

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

C.10 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)] [40 CFR 64][326 IAC 3-8]

(a) For new units:

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

(b) For existing units:

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

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

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

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

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

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

C.11 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment, for Unit 7 Bypass stack, Unit 5 and Unit 6. For a boiler, the COM shall be in operation in accordance with 326 IAC 3-5 and 40 CFR Part 60 at all times that the forced 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 times and reasons 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 in line within twenty-four (24) hours of shutdown or malfunction or 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.

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

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

(3) Method 9 readings are not required on stacks with operating scrubbers.

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

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

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

C.12 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. The analog instrument shall be capable of measuring values outside of the normal range.

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

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

C.13 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.14 Risk Management Plan [326 IAC 2-7-5(11)] [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.15 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]

(I) 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.16 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(35).

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

C.17 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(35).

C.18 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, where applicable:
    (AA) All calibration and maintenance records.
    (BB) All original strip chart recordings for continuous monitoring instrumentation.
    (CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:
    (AA) The date, place, as defined in this permit, and time of sampling or measurements.
    (BB) The dates analyses were performed.
    (CC) The company or entity that performed the analyses.
    (DD) The analytical techniques or methods used.
    (EE) The results of such analyses.
    (FF) The operating conditions as existing at the time of sampling or measurement.

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

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

(c) 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.19 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(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(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;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(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 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit other than Electric Utility Steam Generating 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).

(f) 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

(g) If the Permittee is required to comply with the record keeping provisions of (d) in Section C – General Record Keeping Requirements for an "project" (as defined in 326 IAC 2-2-1 (qq) and/or 326 IAC 2-3-1 (ll)) at an existing Electric Utility Steam Generating Unit, then for that project the

Permittee shall:

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

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

(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.20 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Before Conversion of Boiler number 50 to Natural Gas

(a) One (1) Combustion Engineering Boiler number 50 (also referred to as Unit 5). Boiler 50 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 50. Installation date for Boiler 50 is 1958.

After conversion of Boiler number 50 to Natural Gas

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 (also referred to as Unit 5), constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

Before Conversion of Boiler number 60 to Natural Gas

(b) One (1) Combustion Engineering Boiler number 60 (also referred to as Unit 6). Boiler 60 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 60. Installation date for Boiler 60 is 1961.

After conversion of Boiler number 60 to Natural Gas

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 (also referred to as Unit 6), constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 (also referred to as Unit 7). Boiler 70 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Boiler 70 is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, Boiler 70 exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of Boiler 70. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler number 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(e) One (1) General Electric Gas Turbine Engine number GT1 identified as Unit GT1. Unit GT1 is a distillate oil fired unit with a design heat input capacity rated at 299.0 million Btu per hour and exhausting at Stack/Vent ID GT1-1. Model number MS 5000. Equipped with no add on air pollution control equipment. Installation date for Unit GT1 is 1973.

(f) One (1) General Electric Gas Turbine Engine number GT2 identified as Unit GT2. Unit GT2 is a distillate oil fired unit with a design heat input capacity rated at 299.0 million Btu per hour and exhausting at Stack/Vent ID GT2-1. Model number MS 5000. Equipped with no add on air pollution control equipment. Installation date for Unit GT2 is 1973.

(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

(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.1.0 Prevention of Significant Deterioration (PSD) Minor Limits and Conversion of Existing Operation for Boiler 50, Boiler 60 and Boiler 70 to Natural Gas [326 IAC 2-2]

(a) After the startup of Boiler 50 & Boiler 60 to natural gas, the Permittee shall discontinue the use of coal in Boiler 50 & Boiler 60.

(b) Within thirty (30) days after the date Boiler 50 & Boiler 60 are converted to natural gas, the Permittee shall provide a notification to IDEM indicating the date Boiler 50 & Boiler 60 were converted to natural gas.

(c) After the startup of Boiler 70 on natural gas, the Permittee shall discontinue the use of coal in Boiler 70.

(d) Within thirty (30) days after the date Boiler 70 is converted to natural gas, the Permittee shall provide a notification to IDEM indicating the date Boiler 70 was converted to natural gas.

(e) The combined VOC emissions from the Boiler 50, Boiler 60, (approved in 2013 for modification) Boiler 70 (approved in 2015 for modification) and the auxiliary boiler (approved in 2015 for construction) shall not exceed 96.90 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit, will ensure that the net VOC emissions from Boiler 50, Boiler 60, Boiler 70 and the auxiliary boiler are less than 40 tons per year and renders the requirements of 326 IAC 2-2 (PSD) not applicable to the Boiler 50, Boiler 60, (approved in 2013 for modification) Boiler 70 (approved in 2015 for modification) and the auxiliary boiler (approved in 2015 for construction).

(f) Condition D.1.0(e) shall be effective after the conversion of Boiler 50, 60 and 70 to natural gas.

D.1.1 Marion County [326 IAC 6.5-6][326 IAC 2-7-5]

(a) Pursuant to 326 IAC 6.5-6 (Marion County), the Permittee shall comply with the following emission limitations for particulate (PM):

Unit ID	PM Limit (pounds PM per million Btu)	PM Limit (tons per year)
Boiler number 50	0.135	82.2
Boiler number 60	0.135	82.2
Boiler number 70	0.10	830.7
Unit GT1 (Gas Turbine GT1)	0.015	0.28
Unit GT2 (Gas Turbine GT2)	0.015	0.28

(b) Pursuant to 326 IAC 6.5-6-1(b) (Marion County), the Permittee shall be considered in compliance with the tons per year emission limits if within five percent (5%) of the emission limit established pursuant to 326 IAC 6.5-6.

(c) Condition D.1.1 shall cease to apply to Boiler 50 & Boiler 60 (Unit 5 & Unit 6) after Boiler 50 & Boiler 60 are converted to natural gas.

(d) Condition D.1.1 shall cease to apply to Boiler 70 after Boiler 70 is converted to natural gas.

D.1.2 Sulfur Dioxide (SO_2) Emission Limitations: Marion County [326 IAC 7-4-2]

(a) Pursuant to 326 IAC 7-4-2 (Sulfur Dioxide Emission Limitations: Marion County), the Permittee shall comply with the following emission limitations in pounds per million Btu:

Unit ID	SO_2 Limit (pounds per million Btu)
Boiler number 50 and Boiler number 60	4.7
Boiler number 70	5.3
Unit GT1 and Unit GT2 (Gas Turbines GT1 and GT2)	0.35

(b) As an alternative to the emission limitations listed above, pursuant to 326 IAC 7-4-2, Unit 5, 6 and Unit GT1 and GT2 may comply with any one (1) of the sets of alternative emission limitations in pounds per million Btu as follows:

Alternative Scenario	Unit ID	SO_2 Limit (pounds per million Btu)
1	Boiler number 50 and Boiler number 60	5.2
	Unit GT1 and GT2 (Gas Turbines GT1 and GT2)	0.0
2	Boiler number 50 and Boiler number 60	5.0
	Unit GT1 and GT2 (Gas Turbines GT1 and GT2)	0.4
3	Boiler number 50 and Boiler number 60	4.1
	Unit GT1 and GT2 (Gas Turbines GT1 and GT2)	0.3
4	Boiler number 50 and Boiler number 60	3.9
	GT1 and GT2 (Gas Turbines GT1 and GT2)	0.35

(1) IDEM, OAQ shall be notified prior to the reliance by the Permittee on any one (1) of the sets of alternative emission limitations as listed in the Table above.

(2) A log of hourly operating status for each boiler shall be maintained and made available to IDEM, OAQ upon request. A daily summary indicating which boilers were in service during the day shall be submitted to IDEM, OAQ quarterly. In addition, records of the daily average sulfur content, heat content, and sulfur dioxide emission rate for each day in which an alternative set of emission limitations is used shall be submitted to IDEM, OAQ quarterly.

(3) For the purposes of 326 IAC 7-2-1(c)(1), during thirty (30) day periods in which the Permittee relies on more than one (1) set of alternative emission limitations, a separate thirty (30) day rolling weighted average for each set of limitations shall be determined. Each thirty (30) day rolling average shall be based on data from the previous thirty (30) operational days within the last ninety (90) days for that set of limitations. If the Permittee does not operate thirty (30) days under any one (1) set of limitations within the last ninety (90) days, the rolling weighted average shall be based on all operational days within the last ninety (90) days for that set of limitations.

(c) Condition D.1.2 - Sulfur Dioxide (SO_2) Emission Limitations, shall not apply to Boiler 50, & Boiler 60 after Boiler 50, & Boiler 60 are converted to natural gas.

(d) Condition D.1.2 - Sulfur Dioxide (SO_2) Emission Limitations, shall not apply to Boiler 70 after Boiler 70 is converted to natural gas.

D.1.3 Reserved

D.1.4 Startup, Shutdown and Other Opacity Limits [326 IAC 5-1-3(e)(2)] [326 IAC 5-1-3(b)]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), the following applies to Boiler 50, Boiler 60 and Boiler 70 Bypass Stack:

(1) When building a new fire in Boiler 50 or Boiler 60, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of twenty-five (25) six (6)-minute averaged periods (2.5 hours) during the startup period, or until the flue gas temperature entering the electrostatic precipitator reaches two hundred and fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitator, whichever occurs first. [326 IAC 5-1-3(e)(2)]

(2) When building a new fire in Boiler 70 Bypass Stack, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of fifty (50) six (6)-minute averaged periods (5.0 hours) during the startup period, or until the flue gas temperature entering the electrostatic precipitator reaches two hundred and fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitator, whichever occurs first. [326 IAC 5-1-3(e)(2)]

(3) When shutting down Boiler 50, Boiler 60 and/or Boiler 70 Bypass Stack, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of ten (10) six (6)-minute averaging periods (1.0 hours) for each Unit.
[326 IAC 5-1-3(e)(2)]

(4) Operation of the electrostatic precipitator for each Unit is not required during these times.
[326 IAC 5-1-3(e)]

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

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

(d) Condition D.1.4(a), (b) and (c) - Temporary Alternative Opacity Limitations, shall not apply to Boiler 50 & Boiler 60 after Boiler 50, & Boiler 60 are converted to natural gas.

(e) Condition D.1.4(a), (b) and (c) - Temporary Alternative Opacity Limitations, shall not apply to Boiler 70 after Boiler 70 is converted to natural gas.

Compliance Determination Requirements

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

(a) Compliance with the PM limitation in Condition D.1.1(a) for Boilers 50 and 60, identified as Units 5 and 6, shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. This test shall be repeated by December 31 of every second calendar year following the most recent valid compliance demonstration.

(b) Condition D.1.5 - Testing Requirements, shall not apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to Natural Gas.

(c) Condition D.1.5 - Testing Requirements, shall not apply to Boiler 70 after the conversion of Boiler 70 to Natural Gas.

D.1.5.1 VOC Emissions Compliance Determination Requirements [326 IAC 2-2]

(a) In order to determine compliance status with Condition D.1.0(e) - Prevention of Significant Deterioration (PSD) Minor Limits and Conversion of Existing Operation for Boiler 50, Boiler 60 & Boiler 70 to Natural Gas, the Permittee will determine the VOC emissions using the following equation:

$$\text{VOC emissions (tons/month)} = \{(EFng * P_{U5}) + (EFng * P_{U6}) + (EFng * P_{U7}) + (EFng * P_{AB})\} / 2000 \text{ lbs/ton}$$

Where:

EFng = Emission Factor for natural gas combustion, based on either the AP-42 factor of 0.0054 lbs/MMBtu or the results of the most recent valid stack test on a particular unit for VOCs.

P_{U5} = MMBtu fired for the month for Boiler 50.

P_{U6} = MMBtu fired for the month for Boiler 60.

P_{U7} = MMBtu fired for the month for Boiler 70.

P_{AB} = MMBtu fired for the month for the auxiliary boiler.

(b) Condition D.1.5.1(a) shall be effective after the conversion of Boiler 50, Boiler 60 and Boiler 70 to natural gas.

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

(a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitators (ESPs) shall be operated at all times that Boilers 50, 60 and 70 are in operation.

(b) Condition D.1.6 Operation of Electrostatic Precipitator, shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to natural gas.

(c) Condition D.1.6 Operation of Electrostatic Precipitator, shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.7 Continuous Monitoring of Emissions [326 IAC 3-5][40 CFR 64]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous opacity monitoring systems for Boiler 50, Boiler 60 and Boiler 70 Bypass Stack shall be calibrated, maintained, and operated for measuring opacity, which meets the performance specifications of 326 IAC 3-5-2.

(b) Pursuant to Commissioner's Order #2008-02, in lieu of the requirement to monitor opacity in the stack exhaust from the scrubbed stack of Boiler 70, in accordance with 326 IAC 3-5-1(c)(2)(A), the Permittee shall comply with the following alternative monitoring plan.

Compliance with PM limitations in Condition D.1.1 shall be demonstrated using a certified PM CEMS installed and certified in accordance with US EPA Performance Specification 11 (PS-11) and operated in accordance with Procedure 2 of Appendix F to 40 CFR 60.

(c) Condition D.1.7 - Continuous Monitoring of Emissions, shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to natural gas.

(d) Condition D.1.7 - Continuous Monitoring of Emissions, shall not apply Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.8 Sulfur Dioxide Emissions (SO_2) and Sulfur Content [326 IAC 7-2][326 IAC 7-4-2]

Compliance for Unit 5, Unit 6 and Unit 7 shall be determined as follows:

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of the SO_2 limitation(s) in pounds per million Btu for Boiler 50, Boiler 60 and Boiler 70 stated in Condition D.1.2, using a thirty (30) day rolling weighted average.

(b) The Permittee shall demonstrate compliance with these requirements through the operation of a continuous emissions monitor.

(c) Condition D.1.8(a) and (b), shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to natural Gas.

(d) Condition D.1.8(a) and (b), shall not apply to Boiler 70 after the conversion of Boiler 70 to natural Gas.

D.1.9 Sulfur Dioxide Emissions (SO_2) and Sulfur Content [326 IAC 7-2][326 IAC 7-4-2][326 IAC 3-7-4]

Compliance for Unit GT1 and Unit GT2 shall be determined as follows:

(a) Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of the SO_2 limitation(s) in pounds per million Btu for Unit GT1 and Unit GT2 stated in Condition D.1.2 using a calendar month average.

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

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

(2) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with 327 IAC 3-7-4(a).

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

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

(C) Oil samples shall be collected from the transfer pipe as oil is being unloaded from the tanker truck load and is being transferred to the storage tank.

(c) Pursuant to 326 IAC 7-2-1(d), compliance or noncompliance with the emission limitations contained in 326 IAC 7-4 may be determined by a stack test conducted in accordance with 326 IAC 3-6 utilizing procedures outlined in 40 CFR 60, Appendix A, Method 6, 6A, 6C or 8.

(d) A determination of noncompliance, pursuant to either 326 IAC 7-2-1(d) or 326 IAC 7-2-1(e), shall not be refuted by evidence of compliance pursuant to the other method.

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

D.1.10 Compliance Schedule for National Emission Standard for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR 63, Subpart UUUUU]

Pursuant to Indiana Code § 13-14-6 and in order to secure compliance with 40 CFR 63, Subpart UUUUU, Indianapolis Power & Light Company, Harding Street is subject to the following order:

(1) Indianapolis Power & Light Company shall submit a status report with fifteen (15) days of completion of the following milestones indicating the actual dates of completion:

(a) The dates on-site construction of new generation or conversion to firing natural gas identified in Attachment E for Harding Street Boilers 50 and 60 are initiated, and

(b) The date on-site construction of new generation or conversion to firing natural gas identified in Attachment E for Harding Street Boilers 50 and 60 are completed.

(c) The dates on-site construction for the installation of the emission control equipment and upgrades identified in Attachment E for Harding Street Boiler 70 are initiated, and

(d) The dates on-site construction for the installation of the emission control equipment and upgrades identified in Attachment E for Harding Street Boiler 70 are completed.

(e) The dates by which final compliance with 40 CFR 63, Subpart UUUUU for Harding Street Boilers 50, 60 and 70 are achieved.

(2) Boiler 50, 60 and 70 shall comply with the standards set forth in 40 CFR 63, Subpart UUUUU no later than April 16, 2016.

(3) Condition D.1.10(1) and (2), shall not apply to Boiler 50, and Boiler 60 after the conversion of Boiler 50, and Boiler 60 to natural gas.

(4) Condition D.1.10(1) and (2), shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

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

D.1.11 Electrostatic Precipitator Parametric Monitoring [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)][40 CFR 64]

(a) The ability of the ESP's to control particulate emissions shall be monitored once per day, when the Units are in operation, by measuring and recording the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets.

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

(c) The requirements in (a) and (b) above do not apply to Unit 7 when exhausting through the scrubbed stack.

(d) Condition D.1.11 - Electrostatic Precipitator Parametric Monitoring, shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to natural gas.

(e) Condition D.1.11 - Electrostatic Precipitator Parametric Monitoring, shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.12 Opacity Readings [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) Except during periods of startup and shutdown, appropriate response steps shall be taken whenever opacity exceeds twenty-five percent (25%) for three (3) consecutive six (6) minute averaging periods for Boiler 50 or Boiler 60. Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty five percent (25%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Except during periods of startup and shutdown, appropriate response steps will be taken whenever opacity exceeds twenty percent (20%) for three (3) consecutive six (6) minute averaging periods for Boiler 70 Bypass Stack. Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(c) Opacity readings in excess of the levels set forth in subparagraphs (a) and (b) of this Condition but not exceeding the opacity limit for the Unit specified are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

(d) The Permittee may request that the IDEM, OAQ approve a different opacity trigger level than the one specified in (a), (b) and (c) 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.

(e) Condition D.1.12 - Opacity Readings, shall no longer apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to natural gas.

(f) Condition D.1.12 - Opacity Readings, shall no longer apply Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.13 Reserved

D.1.14 NOx and SO_2 Continuous Emission Monitoring Systems [326 IAC 2-7-6][326 IAC 2-7-5(3)][40 CFR 75]

(a) The Permittee shall install, certify, calibrate, maintain and operate continuous emission monitoring systems (CEMS) and related equipment measuring NOx and SO_2 emissions from Boiler 50, Boiler 60 and Boiler 70.

(1) These continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60 or any other relevant performance specification, and certification requirements pursuant to 326 IAC 3-5-3.

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

(b) Whenever the SO_2 continuous emission monitoring systems (CEMS) on Boiler 50 or Boiler 60 is malfunctioning or down for repairs or adjustments and a backup CEMS is not brought on-line for more than 24 hours, the following shall be used to provide information related to SO_2 emissions:

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

or

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

(c) Whenever the SO_2 continuous emissions monitoring system (CEMS) on Unit 7 is malfunctioning or down for repairs or adjustment and a backup CEMS is not brought on-line, 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 and a back-up CEMS is not brought on-line, the Permittee shall substitute an average of the quality assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(2) Whenever the SO_2 continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustment for twenty-four (24) hours or more, and a back-up CEMS cannot be brought on on-line, the Permittee shall comply with the requirements of 40 CFR 75 Subpart D.

(d) Condition D.1.14(b), shall not apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to natural gas.

(e) Condition D.1.14(c), shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.15 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 2-7-5(3)(A)]

(a) The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Boiler 7 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a)(1) through (a)(2).

(1) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11.

(2) Compliance with the applicable particulate emission 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.

(b) Whenever Boiler 7 exhausts to the scrubbed stack and this particulate (PM) continuous emission monitoring system (CEMS) is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used to provide information related to particulate emissions:

(1) The ability of the FGD to control particulate matter emissions shall be monitored once per day when Boiler 7 is in operation by measuring and recording the following:

(a) Number of recycle pumps in service; and

(b) Absorber pH.

(2) As long as the number of recycle pumps and the slurry pH indicate normal operation of the FGD, any missing daily average data (for purposes of showing compliance with the tons per year limit) will be replaced with the average PM emissions rate from the day before and the day after the missing day.

(c) Condition D.1.15 shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

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

D.1.16 Record Keeping Requirements

(a) To document the compliance status with Section C - Opacity and Conditions D.1.1, D.1.4, D.1.5, D.1.11, and D.1.15, the Permittee shall maintain records in accordance with (1) through (8) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C – Opacity and Conditions D.1.1 and D.1.4:

(1) Monthly and twelve (12) consecutive month distillate oil consumption in Units GT1 and GT2;

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

(3) PM continuous emissions monitoring data associated with Boiler 7 scrubbed stack as required in Condition D.1.15.

(4) All continuous opacity monitoring data, pursuant to 326 IAC 3-5;

(5) The results of all visible emission (VE) notations. 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);

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

(7) To document the compliance status with Condition D.1.11, the Permittee shall maintain a daily record of the primary and secondary voltages and the current readings of the transformer-rectifier sets of the electrostatic precipitators, identified as Control Equipment ID CE 50 and Control Equipment ID CE 60, controlling emissions from Boiler 50 and Boiler 60, respectively. The Permittee shall include in its daily record when the primary and secondary voltage and current readings are not taken and the reason for the lack of primary and secondary voltage and current readings (e.g. the process did not operate that day).

(8) To document the compliance status with D.1.15, the Permittee shall maintain a record of the number of recycle pumps in service and the absorber pH associated with the FGD when Boiler 7 exhausts to the scrubbed stack and PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more and a backup CEMS is not brought on-line. On

days when Boiler 7 exhausts to the scrubbed stack and PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more and a backup CEMS is not brought on-line, the Permittee shall include in its record when readings are not taken and the reason for the lack of readings. (e.g. the boiler did not operate that day.)

(b) To document the compliance status with Condition D.1.2, D.1.8 and D.1.14, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the SO_2 limit established in Condition D.1.2 for Boiler 50, Boiler 60 and Boiler 70.

(1) When using SO_2 CEMs to demonstrate compliance, all SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6 and 326 IAC 7-2-1(t);

(2) When using fuel sampling and analysis to demonstrate compliance, all fuel sampling and analysis data, pursuant to 326 IAC 7-2.

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

(4) The substitute data used for the missing data periods if data substitution pursuant to 40 CFR Part 75 Subpart D is used to provide data for the SO_2 CEM downtime, in accordance with Condition D.1.14.

(c) To document the compliance status with Condition D.1.2 and D.1.9, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be complete and sufficient to establish compliance with the SO_2 limit established in Condition D.1.2 for Unit GT1 and Unit GT2.

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

(2) Monthly weighted average sulfur content;

(3) Fuel heat content;

(4) Fuel consumption;

(5) Monthly weighted average sulfur dioxide emission rate in pounds per million Btu;

(6) A log of hourly operating status for each Unit and a daily summary indicating which Units were in service during the day.

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

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

(f) Conditions D.1.16(a)(4), (a)(6), and (a)(7) - Recordkeeping Requirements, shall not apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to Natural Gas.

(g) Conditions D.1.16(a)(3), (a)(4), (a)(6), (a)(7) and (a)(8) shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.17 Reporting Requirements

(a) A quarterly report of opacity exceedances, continuous emission monitor exceedances, a quarterly summary of Boiler 70 PM emissions, and a quarterly summary of the information to document compliance status with Conditions D.1.14 shall be submitted no later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee'ss obligation with regard to the reporting required by this condition. 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(35).

(b) A quarterly summary of the information to document the compliance status with Condition D.1.0(e) shall be submitted to the address listed in Section C- General Reporting Requirements, of this permit, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

(c) Condition D.1.17(a) shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) General Electric Gas Turbine Engine number GT4 identified as Unit GT4. Unit GT4 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 875.0 million Btu per hour and exhausting at Stack/Vent ID GT4-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT4 is 1994.

(b) One (1) General Electric Gas Turbine Engine number GT5 identified as Unit GT5. Unit GT5 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 867.0 million Btu per hour and exhausting at Stack/Vent ID GT5-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT5 is 1995.

(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 General Provisions Relating to NSPS [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 Unit GT4 and Unit GT5 as described in this section except when otherwise specified in 40 CFR Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines).

D.2.2 New Source Performance Standards (NSPS) [326 IAC 12][40 CFR 60, Subpart GG]

Pursuant to 326 IAC 12 (New Source Performance Standards) and 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines), the Permittee shall:

(a) Limit nitrogen oxides (NO_X) emissions, as required by 40 CFR 60.332, to:

$$STD = (0.0075) * (14.4/Y) + F$$

Where: STD = Allowable NO_X emissions in percent by volume at fifteen percent (15%) oxygen and on a dry basis (ppm = percent by volume x 10^4).

Y = Manufacturer's rated heat rate at manufacturer's rated load or, actual measured heat rate based on the lower heating value of fuel as measured at peak load in kilojoules per watt hour. Y shall not exceed 14.4 kilojoules per watt hour.

F = The fuel bound nitrogen allowance as defined in 40 CFR 60.332(a)(3).

(b) Limit sulfur dioxide (SO_2) emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at fifteen percent (15%) oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to eight tenths percent (0.8%) by weight.

D.2.3 Nitrogen Oxides (NO_X) – Best Available Control Technology (BACT) [326 IAC 2-2] [Construction Permit 097-2206-00033]

Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration Requirements) and Construction Permit 097-2206-00033 issued August 27, 1992, Unit GT4 and Unit GT5 shall comply with the following BACT requirements for nitrogen oxides (NO_X) emissions:

(a) Application of wet injection;

(b) When burning natural gas, the NO_X emission rate shall not exceed forty two (42) ppmv at fifteen percent (15%) oxygen and on a dry basis;

(c) When burning distillate oil, the NO_X emission rate shall not exceed sixty five (65) ppmv at fifteen percent (15%) oxygen and on a dry basis.

Pursuant to Operation Condition 13 of the Construction Permit 097-2206-00033 issued August 27, 1992, compliance with BACT requirements for nitrogen oxides (NO_X) emissions shall ensure compliance with NO_X emission rate specified in Condition D.2.2(a) and 40 CFR 60.332(a)(1).

D.2.4 PSD Minor Limit [326 IAC 2-2][Construction Permit 097-2206-00033]

Pursuant to 326 IAC 2-2(Prevention of Significant Deterioration Requirements) and Construction Permit 097-2206-00033 issued August 27, 1992:

(a) The fuel sulfur weight percent of distillate oil fired in Unit GT4 and Unit GT5 is limited to five hundredths (0.05) percent by weight; and

(b) The combined total natural gas throughput (no fuel oil combusted) for Unit GT4 and Unit GT5 is limited to 6300 million cubic feet per twelve (12) consecutive month period with compliance determined at the end of each month; and

(c) The combined total distillate fuel oil throughput (no natural gas combusted) for Unit GT4 and Unit GT5 is limited to 12.8 million gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(d) One gallon of distillate fuel oil can be substituted for each 293 cubic feet reduction of natural gas consumption per twelve (12) consecutive month period with compliance determined at the end of each month.

This is equivalent to sulfur dioxide (SO_2) emission of less than forty (40) tons per twelve (12) consecutive month period with compliance determined at the end of each month such that 326 IAC 2-2 will not apply to SO_2 emissions but will apply to NO_X emissions.

D.2.5 Particulate Matter Limitations Except Lake County [326 IAC 6.5-1-2(a)]

Pursuant to 326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County), particulate (PM) emissions from Unit GT4 and Unit GT5 shall each not exceed three hundredths (0.03) grains per dry standard cubic foot of exhaust air.

D.2.6 Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide (SO_2) Emission Limitations), SO_2 emissions from Unit GT4 and Unit GT5 shall each not exceed five tenths (0.5) pounds per million Btu when burning distillate oil. Compliance with 326 IAC 12 (New Source Performance Standards) and 40 CFR 60.333, Subpart GG (Standards of Performance for Stationary Gas Turbines) will demonstrate compliance with 326 IAC 7-1.1-2 (Sulfur Dioxide (SO_2) Emission Limitations).

D.2.7 Opacity Limitations [326 IAC 2-2] [Construction Permit 097-2206-00033] [326 IAC 5-1]

Pursuant to the Construction Permit 097-2206-00033 issued August 27, 1992, opacity for Unit GT4 and Unit GT5 each shall not exceed twenty percent (20%) as determined by 40 CFR Part 60, Appendix A, Method 9.

Compliance Determination Requirements

D.2.8 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

In order to show compliance with Condition D.2.3 for Unit GT4 and Unit GT5, the Permittee shall conduct NOx emissions testing by a performance stack test utilizing methods as approved by the Commissioner. This test shall be repeated by December 31 of every fifth calendar year following the most recent valid compliance demonstration. Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.2.9 New Source Performance Standard (NSPS) [326 IAC 12][40 CFR Part 60, Subpart GG][40 CFR 64]

Pursuant to 40 CFR 60.334(a), the Permittee shall operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in Unit GT4 and Unit GT5.

D.2.10 Sulfur and Nitrogen Content [326 IAC 12] [40 CFR 60.334]

Pursuant to 40 CFR 60.334(b), the Permittee shall monitor the daily sulfur content and the nitrogen content of the fuel being fired in Unit GT4 and Unit GT5 in accordance with the EPA custom schedule approved on October 26, 2000.

D.2.11 Sulfur Dioxide Emissions (SO_2) and Sulfur Content [326 IAC 7-2][326 IAC 7-1.1-2]

Compliance for Unit GT4 and Unit GT5 shall be determined as follows:

(a) Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall demonstrate that the sulfur dioxide emissions for Unit GT4 and Unit GT5 each do not exceed the equivalent of five tenths (0.5) pounds per million Btu using a calendar month average.

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

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

(2) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with 327 IAC 3-7-4(a).

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

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

(C) Oil samples shall be collected from the transfer pipe as oil is being unloaded from the tanker truck load and is being transferred to the storage tank.

(c) Pursuant to 326 IAC 7-2-1(d), compliance or noncompliance with the emission limitations contained in 326 IAC 7-4 may be determined by a stack test conducted in accordance with 326 IAC 3-6 utilizing procedures outlined in 40 CFR 60, Appendix A, Method 6, 6A, 6C or 8.

(d) A determination of noncompliance, pursuant to either 326 IAC 7-2-1(d) or 326 IAC 7-2-1(e), shall not be refuted by evidence of compliance pursuant to the other method.

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

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

D.2.12 Sulfur and Nitrogen Content [326 IAC 12][40 CFR 60.334]

The Permittee shall comply with the following custom monitoring schedule for Unit GT4 and Unit GT5 as approved for the site by the USEPA on October 26, 2000:

(a) Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

(b) Sulfur Monitoring:

(1) Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternate method. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM 3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(d).

(2) Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

(3) If after the monitoring required in item (b)(2) above, or herein. The sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(4) Should any sulfur analysis as required in items (b)(2) or (b)(3) above indicate noncompliance with 40 CFR 60.333, the Permittee shall notify IDEM, OAQ and USEPA of such excess emissions and the custom schedule shall be re-examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

(5) If there is a change in fuel supply, the Permittee must notify IDEM, OAQ and USEPA of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

(6) Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three (3) years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

D.2.13 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) Visible emission (VE) notations of Unit GT4 and/or Unit GT5 stack exhaust(s) shall be performed once per day during normal daylight operations when the given unit is operating for more than two (2) continuous daylight hours and combusting fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) If abnormal emissions are observed at Unit GT4 and/or Unit GT5 exhaust, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

(c) "Normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(d) 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.2.14 Record Keeping Requirements

(a) To document the compliance status with Conditions D.2.2, D.2.3, D.2.4, D.2.5, D.2.6, D.2.7, D.2.8, D.2.9, D.2.11, D.2.12 and D.2.13, the Permittee shall maintain records in accordance with (1) through (5) below. Records shall be complete and sufficient to establish compliance with the limits established in Conditions D.2.2, D.2.3, D.2.4, D.2.5, D.2.6 and D.2.7:

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

(2) All fuel nitrogen content and sulfur content monitoring data;

(3) Records of fuel usage;

(4) Records of the fuel consumption and the ratio of water to fuel being fired in Unit GT4 and Unit GT5; and

(5) Visible emission (VE) notations. 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 records required by this condition.

D.2.15 Reporting Requirements

(a) A quarterly summary of the information to document compliance status with Conditions D.2.4 and D.2.11 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee'ss obligation with regard to the reporting required by this condition. 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(35).

(b) Periods of excess emissions shall be reported in accordance with the requirements of 40 CFR 60.334(c).

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(i) One (1) General Electric Gas Turbine Model number PG7241 identified as Unit GT6. Unit GT6 is a natural gas fired unit with a design heat input capacity rated at 1,660 MMBtu per hour and exhausting at Stack/Vent ID GT-6. NO_X emissions will be controlled by dry low NO_X burners. Installation date for Unit GT6 is 2002.

(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 General Provisions Relating to NSPS [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 Unit GT6 as described in this section except when otherwise specified in 40 CFR Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines).

D.3.2 New Source Performance Standards (NSPS) [326 IAC 12] [40 CFR 60, Subpart GG]

Pursuant to 40 CFR 60.330 Subpart GG (Standards of Performance for Stationary Gas Turbines) and 326 IAC 12 (New Source Performance Standards), the Permittee shall:

(a) Limit Nitrogen Oxides (NO_X) emissions, as required by 40 CFR 60.332, to:

$$STD = (0.0075) * (14.4/Y) + F$$

Where: STD = Allowable NO_X emissions in percent by volume at fifteen percent (15%) oxygen and on a dry basis (ppm = percent by volume x 10^4).

Y = Manufacturer's rated heat rate at manufacturer's rated load or, actual measured heat rate based on the lower heating value of fuel as measured at peak load in kilojoules per watt hour. Y shall not exceed 14.4 kilojoules per watt hour.

F = The fuel bound nitrogen allowance as defined in 40 CFR 60.332(a)(3).

(b) Limit Sulfur dioxide (SO_2) emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at fifteen percent (15%) oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to eight tenths percent (0.8%) by weight.

D.3.3 PSD Minor Limit [326 IAC 2-2] [Minor Permit Modification 097-14666-00033]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration Requirements) not applicable to Unit GT6 and pursuant to Operation Condition number 9 of the Minor Permit Modification 097-14666-00033 issued on November 9, 2001:

(a) Nitrogen Oxides (NO_X) emissions are limited to less than forty (40) tons per twelve (12) consecutive month period with compliance demonstrated at the end of each month such that 326 IAC 2-2 will not apply. Compliance with the Nitrogen Oxides (NO_X) emissions limitation shall be demonstrated by installing and operating a continuous emission monitor for NO_X emissions from Unit GT6 in accordance with 326 IAC 3-5.

Compliance Determination Requirements

D.3.4 Continuous Emissions Monitoring [326 IAC 3-5] [Minor Permit Modification 097-14666-00033]

Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and Operation Condition number 9 of the Minor Permit Modification 097-14666-00033 issued on November 9, 2001, continuous monitoring systems for Unit GT6 shall be calibrated, maintained, and operated for measuring NO_X emissions which meets the performance specifications of 326 IAC 3-5-2 (Continuous Monitoring of Emissions).

D.3.5 Sulfur and Nitrogen Content [326 IAC 12] [40 CFR 60.334]

Pursuant to 40 CFR 60.334(b), the Permittee shall monitor the daily sulfur content and the nitrogen content of the fuel being fired in Unit GT6 in accordance with the EPA custom schedule approved on June 16, 2004.

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

D.3.6 Sulfur and Nitrogen Content [326 IAC 12] [40 CFR 60.334]

As stated in the U.S. EPA Region 5 approval letter dated June 16, 2004, the Permittee shall comply with the following custom monitoring schedule for Unit GT6 as approved by the U.S. EPA for Unit GT4 and Unit GT5 on October 26, 2000:

(a) Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

(b) Sulfur Monitoring:

(1) Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternate method. The reference methods are ASTM D1072-80; ASTM D3031-81; ASTM 3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(d).

(2) Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

(3) If after the monitoring required in item (b)(2) above, or herein. The sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(4) Should any sulfur analysis as required in items (b)(2) or (b)(3) above indicate noncompliance with 40 CFR 60.333, the Permittee shall notify IDEM, OAQ and USEPA of such excess emissions and the custom schedule shall be re-examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

(5) If there is a change in fuel supply, the Permittee must notify IDEM, OAQ and USEPA of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

(6) Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three (3) years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

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

D.3.7 Record Keeping Requirements

(a) To document the compliance status with Conditions D.3.2, D.3.3, D.3.4, D.3.5 and D.3.6, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Conditions D.3.2 and D.3.3.

(1) All required fuel nitrogen content and sulfur content monitoring data; and

(2) All required NO_X continuous emission monitoring data;

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

D.3.8 Reporting Requirements

(a) A quarterly summary of the information to document compliance with status Condition D.3.3(a) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee'ss obligation with regard to the reporting required by this condition. 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(35).

(b) Periods of excess emissions shall be reported in accordance with the requirements of 40 CFR 60.334(c)

. SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(j) One (1) General Motors Reciprocating Internal Combustion Standby/Emergency Generator identified as Unit ST14. As an emergency generator, Unit ST14 will be operated less than 500 hours per year. Unit ST14 is distillate oil fired with a design heat input of 27.6 million Btu per hour. Equipped with no add on air pollution control equipment. Exhausting at Stack/Vent ID ST14-1. Installation date for Unit ST14 is 1967.

(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 Particulate Matter Limitations Except Lake County [326 IAC 6.5-1-2(a)]

(a) Pursuant to 326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County), particulate (PM) emissions from Unit ST14 shall not exceed three hundredths (0.03) grains per dry standard cubic foot of exhaust air.

(b) Absent a direct measurement of emissions, compliance is assumed for ST14 provided visible emissions from ST14-1 are normal.

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

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

(a) Visible emission notations of Stack/Vent ID ST14-1 exhaust shall be performed once per day during normal daylight operations when operating and exhausting to the atmosphere when the unit is operating for more than two (2) continuous daylight hours and combusting fuel oil. . A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(e) If abnormal emissions are observed from Unit ST14 stack exhaust, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

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

D.4.3 Record Keeping Requirements

(a) The Permittee shall maintain records of annual operating hours per year for Unit ST14.

(b) To document the compliance status with Condition D.4.2, the Permittee shall maintain records of the visible emission notations of Stack/Vent ID ST14-1 once per day. 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).

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

SECTION D.5 FACILITY CONDITIONS

Facility Description [326 IAC 2-7-5(14)]:

(k) Coal material handling and storage system with a maximum annual capacity of 7.5 million tons per year and described as follows:

(1) One (1) crusher house, consisting of the following equipment:
- (i) Two (2) crushers constructed in 1958;
- (ii) One (1) self cleaning static grizzly constructed in 1996; and
- (iii) One (1) self cleaning static grizzly constructed in 2006.

(2) One (1) covered conveyor system, constructed in 1931, consisting of the following equipment:
- (i) No. 2 conveyor which transfers coal from the railcar receiving area to the crusher house;
- (ii) No. 3 conveyor transfers coal from the crusher to No. 4 conveyor;
- (iii) No. 4 conveyor transfers coal from the crusher to the cross-over conveyor;
- (iv) Cross-over conveyor transfers coal from No. 4 conveyor to No. 5 conveyor or to conveyor 705 (which then transfers to conveyor 703 and to Unit 7); and
- (v) No. 5 conveyor transfers coal from the cross-over conveyor to Boiler 50 or Boiler 60.

(3) One (1) covered conveyor system, constructed in 1958 and consisting of the following equipment:
- (i) Conveyors identified as 600A, 600B, 601, 602, 605, and 606. 600A and 600B conveyor transfers coal from the railcar receiving area to 601 and 602 conveyors which transfer coal to the crusher house; and
- (ii) 605 conveyor transfers coal to 606 or 703 conveyors. 605 and 606 conveyors are located inside the building and transfer coal to five (5) conveyors which transfer coal to Unit 5's and Unit 6's coal bunkers.

(4) One (1) covered conveyor system which became commercial in 1973 and consists of the following equipment:
- (i) Conveyors identified as 701 and 702 transfer coal to either the crusher house or the low sulfur coal pile; and
- (ii) Conveyors identified as 703 and 704 are the conveyors which transfer coal from 601, 602, and 605 conveyors to Unit 7's coal bunkers.

(5) One (1) covered conveyor system, constructed in 2006 and consisting of the following equipment:
- (i) Conveyors identified as 801 and 802 transfer coal to the outside high sulfur coal storage pile.

(6) One (1) covered conveyor system, constructed in 2006 and consists of the following equipment subject to 40 CFR Part 60, Subpart Y;
- (i) Conveyors identified as 803 and 804 transfer coal from the high sulfur storage pile to the crusher house.

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

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

D.5.1 General Provisions Relating to NSPS [40 CFR Part 60, Subpart A][326 IAC 12-1]

(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 two (2) covered coal conveyors, identified as 803 and 804, as described in this section except when otherwise specified in 40 CFR Part 60, Subpart Y.

(b) Pursuant to 40 CFR 60.4 and 40 CFR 60.7, the Permittee shall submit all required notifications and reports to:

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

And

Region V, Director, Air and Radiation Division
United States Environmental Protection Agency
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

D.5.2 Standards of Performance for Coal Preparation Plants [40 CFR 60.250, Subpart Y] [326 IAC 12]

Pursuant to 40 CFR 60.250, Subpart Y (Standards of Performance for Coal Preparation Plants), incorporated by reference in 326 IAC 12, the two (2) covered coal conveyors, identified as 803 and 804, shall each comply with the following:

§ 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.

[74 FR 51977, Oct. 8, 2009]

§ 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) *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.

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

(c) *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.

(d) *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.

(e) *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).

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

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

[FR 51977, Oct. 8, 2009]

§ 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.

[74 FR 51977, Oct. 8, 2009]

§ 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 avrages).

(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.

[74 FR 51977, Oct. 8, 2009]

SECTION D.6 FACILITY OPERATION CONDITIONS

Facility Description: [326 IAC 2-7-5(14)]

(l) Limestone transfer from trucks and loader vehicles to the conveyor system, identified as T-1, with a maximum capacity to transfer 230,000 tons of limestone per year and using no control. Constructed in 2006.

(m) Five (5) covered limestone conveyors, identified as T-2, with a maximum capacity to convey 230,000 tons of limestone per year and using no control. Constructed in 2006. Under 40 CFR 60.670, Subpart OOO, T-2 is considered an affected facility.

(n) Two (2) 630 ton capacity limestone storage silos, identified as L7-1 and L7-2, using bin vents LC7-1 and LC7-2 as control, and exhausting to stack/vent LSV7-1 and LSV7-2. Maximum throughput of 230,000 tons of limestone per year. Constructed in 2006. Under 40 CFR 60.670, Subpart OOO, L7-1 and L7-2 are each considered an affected facility.

(o) Two (2) weigh feeders which transfer limestone from the silos to the two (2) enclosed wet ball mills (grinding mills) for grinding limestone, identified as BM7-1 and BM7-2. The ball mill grinding mills are located in a covered building. Constructed in 2006. Under 40 CFR 60.670, Subpart OOO, BM7-1 and BM7-2 are each considered an affected facility.

(p) Gypsum transfer, identified as T-3, with a maximum capacity to transfer 414,000 tons of gypsum per year and using no control. Constructed in 2006.

(q) Six (6) covered gypsum conveyors, identified as T-4, with a maximum capacity to convey 414,000 tons of gypsum and using no control. Constructed in 2006.

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

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

D.6.1 Particulate Matter (PM) [326 IAC 6.5-1-2(a)]

(a) Pursuant to 326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County), particulate matter (PM) emissions from the two (2) limestone storage silos, identified as L7-1 and L7-2, shall each be limited to three hundredths (0.03) grain per dry standard cubic foot of exhaust air.

(b) Absent a direct measurement of emissions, compliance is assumed for L7-1 and L7-2 provided visible emissions from LSV7-1 and LSV7-2 are normal.

D.6.2 PSD Minor Limit [326 IAC 2-2][326 IAC 2-1.1-5]

(a) PM10 emissions from each limestone storage silo, identified as L7-1 and L7-2, shall not exceed 0.19 pounds per hour.

(b) PM emissions from each limestone storage silo, identified as L7-1 and L7-2, shall not exceed 0.022 gr/dscf of exhaust air and shall each not exceed 0.19 pounds per hour.

Compliance with these emission limits will ensure that the limited potential to emit from emission units L7-1 and L7-2, combined with the unrestricted potential to emit from emission units T-1, T-2, T-3, and T-4 is less than twenty-five (25) tons of PM per year and less than fifteen (15) tons of PM10 per year and, therefore, will render the requirements of 326 IAC 2-2 and 326 IAC 2-1.1-5 not applicable.

Compliance Determination Requirements

D.6.3 Particulate Control

(a) In order to comply with Condition D.7.1 and D. 7.2, the bin vent filters identified as LC-1 and LC-2 for particulate control shall be in operation and control emissions from the limestone storage silos at all times that the limestone storage silos are loaded or unloaded.

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

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

D.6.4 Visible Emissions Notations

(a) Visible emission notations of the limestone storage silo stack/vent LSV7-1 and LSV7-2 exhausts shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the unenclosed transfer points for the five (5) covered limestone conveyors, identified as T-2 and of the unenclosed transfer points for six (6) covered gypsum conveyors, identified as T-4 shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

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

D.6.5 Parametric Monitoring

The Permittee shall record the pressure drop across LC7-1 and LC7-2, at least once per week. When for any one reading, the pressure drop is outside the normal range of 0.5 and 5.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. A pressure 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 or Exceedances shall be considered a deviation from this permit.

The instrument used for determining the pressure shall comply with Section C - Instrument

Specifications, and shall be calibrated in accordance with the manufacturer's specifications. The specifications shall be available on site with the Preventive Maintenance Plan.

D.6.6 Broken or Failed Bag Detection

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

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

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

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

D.6.7 Record Keeping Requirements

(a) To *document the compliance status with Condition D.6.4, the Permittee shall maintain the following:*

(1) Records of weekly visible emission notations of the limestone storage silo stack/vent LSV7-1 and LSV7-2 exhausts. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(2) Records of weekly visible emission notations of the unenclosed transfer points for the five (5) covered limestone conveyors, identified as T-2, and of the transfer points for the six (6) covered gypsum conveyors, identified as T-4. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.6.5, the Permittee shall maintain:

Weekly records of the pressure drop across LC7-1 and LC7-2. The Permittee shall include in its weekly record when a pressure drop reading is not taken and the reason for the lack of 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 records required by this condition.

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

D.6.8 General Provisions Relating to NSPS [40 CFR Part 60, Subpart A][326 IAC 12-1]

(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 five (5) covered limestone conveyors, identified as T-2, the two (2) limestone storage silos, identified as L7-1 and L7-2, and the two (2) enclosed wet ball mills (grinding mills), identified as BM7-1 and

BM7-2, as described in this section except when otherwise specified in 40 CFR Part 60, Subpart OOO.

(b) Pursuant to 40 CFR 60.4 and CFR 60.7, the Permittee shall submit all required notifications and reports 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, IN 46204-2251

And

Region V, Director, Air and Radiation Division
United States Environmental Protection Agency
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

D.6.9 New Source Performance Standards for Nonmetallic Mineral Processing Plants [40 CFR 60.670, Subpart OOO][326 IAC 12]

Pursuant to 40 CFR 60.670, Subpart OOO (New Source Performance Standards for Nonmetallic Mineral Processing Plants), the five (5) covered limestone conveyors, identified as T-2, the two (2) limestone storage silos, identified as L7-1 and L7-2, and the two (2) enclosed wet ball mills (grinding mills), identified as BM7-1 and BM7-2, shall each comply with 40 CFR §§ 60.670, 671, 672, 673, 675 and 676 as incorporated by reference in 326 IAC 12-1.

SECTION D.7 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(14)]:

Insignificant Activities

(a) Fuel oil fired combustion sources with heat input equal to or less than two (2) million Btu per hour and firing fuel containing less than five-tenths (0.5) percent sulfur by weight. [326 IAC 6.5-1-2(a)]

(b) Gasoline generators not exceeding 110 horsepower. [326 IAC 6.5-1-2(a)]

(c) Two (2) flyash silos identified as Unit 5/6 Flyash Silo and Unit 7 Flyash Silo for truck loading. Each silo is exhausted to a baghouse. [326 IAC 6.5-1-2(a)]

(d) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2]

(e) One (1) 81 horsepower diesel fired emergency generator identified as Emission Unit ID Generator # 1, installed in 1988, associated with a communication transmitter tower located at 4190 S. Harding Street, Indianapolis, Indiana, 46217. [326 IAC 6.5-1-2(a)]

(f) Grit blast existing steel stack liner [326 IAC 6.5-1-2(a)]

(g) Primer existing steel stack liner with HVLP spray technology [326 IAC 6.5-1-2(a)]

(h) One (1) emergency internal combustion engine used to power a fire pump, identified as FP-1, installed in 1993, with a maximum heat input capacity of 0.56 MMBtu/hr and a rating of 215 horsepower (bhp).

(i) One (1) ponded ash screening operation and associated ash handling, identified as PAS-1, approved for construction in 2013, with a maximum throughput of 200 tons/hr.

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

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

D.7.1 Particulate Matter Limitations Except Lake County [326 IAC 6.5]

(a) Pursuant to 326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County), particulate (PM) emissions from Unit 5/6 Flyash Silo, Unit 7 Flyash Silo, fuel oil fired combustion sources with heat input equal to or less than two (2) million Btu per hour, gasoline generators, Emission Unit ID Generator # 1, primer and grit blasting shall each not exceed three hundredths (0.03) grains per dry standard cubic foot of exhaust air.

(b) Pursuant to 326 IAC 6.5-1-1(b), particulate matter (PM) emissions from ponded ash handling and screen operation (PAS-1) shall not exceed three hundredths (0.03) grains per dry standard cubic feet.

D.7.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]

(a) Pursuant to 326 IAC 8-3-2 (Organic Solvent Degreaser Operations: Cold Cleaner Operation), for cold cleaning operations existing as of January 1, 1980, located in Marion County and which have potential emissions of one hundred (100) tons per year or greater of VOC, the owner or operator of a cold cleaner degreaser shall ensure the following control equipment and operating requirements are met:

(1) Equip the degreaser with a cover;

(2) Equip the degreaser with a device for draining cleaned parts;

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

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

(5) Provide a permanent, conspicuous label that lists the operation requirements in subdivisions (3), (4), (6), and (7);

(6) Store waste solvent only in closed containers;

(7) Prohibit the disposal or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.

(b) The owner or operator of a cold cleaner degreaser subject to this subsection shall ensure the following additional control equipment and operating requirements are met:

(1) Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.
(B) A water cover when solvent used in insoluble in, and heavier than, water.
(C) A refrigerated chiller.
(D) Carbon adsorption.
(E) An alternative system of demonstrated equivalent or better control as those outlined in clauses (A) through (D) that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

(2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.

(3) If used, solvent spray:

(A) must be a solid, fluid stream; and
(B) shall be applied at a pressure that does not cause excessive splashing.

D.7.3 Material requirements for cold cleaner degreasers [326 IAC 8-3-8]

(a) Pursuant to 326 IAC 8-3-8, material requirements specified in this section for use in cold cleaner degreasers apply as follows:

(1) Before January 1, 2015, in Clark, Floyd, Lake, and Porter counties.

(2) On and after January 1, 2015, anywhere in the state.

(b) Material requirements are as follows:

(1) No person shall cause or allow the sale of solvents for use in cold cleaner degreasing operations with a VOC composite partial vapor pressure, when diluted at the manufacturer's recommended blend and dilution, that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit) in an amount greater than five (5) gallons during any seven (7) consecutive days to an individual or business.

(2) No person shall operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

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

D.7.4 Record Keeping Requirements

(a) Record keeping requirements are as follows:

(1) All persons subject to the requirements of subsection (b)(1) shall maintain all of the following records for each sale:

(A) The name and address of the solvent purchaser.
(B) The date of sale (or invoice/bill date of contract servicer indicating service date).
(C) The type of solvent sold.
(D) The volume of each unit of solvent sold.
(E) The total volume of the solvent sold.
(F) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

(2) All persons subject to the requirements of subsection (b)(2) shall maintain each of the following records for each purchase:

(A) The name and address of the solvent supplier.
(B) The date of purchase (or invoice/bill date of contract servicer indicating service date).
(C) The type of solvent purchased.
(D) The total volume of the solvent purchased.
(E) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

(b) All records required by subsection (c) shall be:

(1) retained on-site or accessible electronically from the site for the most recent three (3) year period; and
(2) reasonably accessible for an additional two (2) year period.

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

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(r) One (1) Reciprocating Internal Combustion Engine identified as Unit BSE-2. Unit BSE-2 is a black start diesel-fired engine and not an emergency use engine. Unit BSE-2 has a design heat input of 6.65 million Btu per hour (475 horsepower) and exhausts to Stack/Vent GT2-1. Unit BSE-2 was installed in 1973.

(s) One (1) Reciprocating Internal Combustion Engine identified as Unit BSE-3. Unit BSE-3 is a black start diesel-fired engine and not an emergency use engine. Unit BSE-3 has a design heat input of 6.65 million Btu per hour (475 horsepower) and exhausts to Stack/Vent GT3-1. Unit BSE-3 was installed in 1973.

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

D.8.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-82]

The provisions of 40 CFR 63, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 20-1-1, apply to the black start diesel-fired engines, identified as BSE-2 & BSE-3, except when otherwise specified in 40 CFR 63, Subpart ZZZZ.

D.8.2 NESHAP: Stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82]

The Permittee as an owner/operator of Stationary Compression Ignition Internal Combustion Engines shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment A of this permit):

1. 40 CFR 63.6580
2. 40 CFR 63.6585
3. 40 CFR 63.6590 (a)(1)(ii)
4. 40 CFR 63.6595 (a)(1)
5. 40 CFR 63.6595 (c)
6. 40 CFR 63.6602
7. 40 CFR 63.6605
8. 40 CFR 63.6625 (e),(h),(i)
9. 40 CFR 63.6640 (a),(b),(e)
10. 40 CFR 63.6645 (a)(5)
11. 40 CFR 63.6650
12. 40 CFR 63.6660
13. 40 CFR 63.6665
14. 40 CFR 63.6670
15. 40 CFR 63.6675
16. Table 2c(1)
17. Table 2d(4)
18. Table 6(9)
19. Table 8

SECTION E.1 TITLE IV CONDITIONS

Emissions Unit Description:

Before Conversion of Boiler number 50 to Natural Gas

(a) One (1) Combustion Engineering Boiler number 50 (also referred to as Unit 5). Boiler 50 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 50. Installation date for Boiler 50 is 1958.

After conversion of Boiler number 50 to Natural Gas

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 (also referred to as Unit 5), constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

Before Conversion of Boiler number 60 to Natural Gas

(b) One (1) Combustion Engineering Boiler number 60 (also referred to as Unit 6). Boiler 60 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 60. Installation date for Boiler 60 is 1961.

After conversion of Boiler number 60 to Natural Gas

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 (also referred to as Unit 6), constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 (also referred to as Unit 7). Boiler 70 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Boiler 70 is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, Boiler 70 exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of Boiler 70. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler number 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(g) One (1) General Electric Gas Turbine Engine number GT4 identified as Unit GT4. Unit GT4 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 875.0 million Btu per hour and exhausting at Stack/Vent ID GT4-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT4 is 1994.

(h) One (1) General Electric Gas Turbine Engine number GT5 identified as Unit GT5. Unit GT5 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 867.0 million Btu per hour and exhausting at Stack/Vent ID GT5-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT5 is 1995.

(i) One (1) General Electric Gas Turbine Model number PG7241 identified as Unit GT6. Unit GT6 is a natural gas fired unit with a design heat input capacity rated at 1,660 MMBtu per hour and exhausting at Stack/Vent ID GT-6. NOX emissions will be controlled by dry low NOX burners. Installation date for Unit GT6 is 2002.

(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 B, 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 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(14)]:

Insignificant Activities

(i) One (1) 81 horsepower diesel fired emergency generator identified as Emission Unit ID Generator # 1, installed in 1988, associated with a communication transmitter tower located at 4190 S. Harding Street, Indianapolis, Indiana, 46217. [326 IAC 6.5-1-2(a)]

(j) One (1) emergency internal combustion engine used to power a fire pump, identified as FP-1, installed in 1993, with a maximum heat input capacity of 0.56 MMBtu/hr and a rating of 215 horsepower (bhp).

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.2.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-82]

The provisions of 40 CFR 63, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 20-1-1, apply to the diesel fired emergency generator, identified as Emission Unit #1 and an emergency internal combustion, identified as FP-1, except when otherwise specified in 40 CFR 63, Subpart ZZZZ.

E.2.2 NESHAP: Stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82]

The Permittee as an owner/operator of Stationary Compression Ignition Internal Combustion Engines shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment A of this permit):

1. 40 CFR 63.6580
2. 40 CFR 63.6585
3. 40 CFR 63.6590 (a)(1)(ii)
4. 40 CFR 63.6595 (a)(1)
5. 40 CFR 63.6595 (c)
6. 40 CFR 63.6602
7. 40 CFR 63.6605
8. 40 CFR 63.6612
9. 40 CFR 63.6620 (a)
10. 40 CFR 63.6625 (e),(f),(h),(i)
11. 40 CFR 63.6640 (a),(b),(e),(f)
12. 40 CFR 63.6645 (a)(5)
13. 40 CFR 63.6650 (a)
14. 40 CFR 63.6650 (b)(1-5)
15. 40 CFR 63.6650 (c),(d),(e),(f)
16. 40 CFR 63.6655 (a)(1),(2),(4)
17. 40 CFR 63.6655 (b),(d),(e),(f)
18. 40 CFR 63.6660
19. 40 CFR 63.6665
20. 40 CFR 63.6670
21. 40 CFR 63.6675
22. Table 2c(1)

23. Table 6 (9)
24. Table 7 (a)
25. Table 8

After the Conversion of Boiler number 50, 60 & 70 to Natural Gas

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 (also referred to as Unit 5), constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

(b) One (1) 1,162 MMBtu/hr natural gas fired Combustion Engineering Boiler 60 (also referred to as Unit 6), constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.3.1 General Provisions Relating to NESHAP [326 IAC 20-1][40 CFR Part 63, Subpart A]

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

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

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

E.3.2 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD] [326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart DDDDD, (included as Attachment D of this permit), which are incorporated by reference as 326 IAC 20-95, except as otherwise specified in 40 CFR 63, Subpart DDDDD:

(1) 40 CFR 63.7480
(2) 40 CFR 63.7485
(3) 40 CFR 63.7490

(4) 40 CFR 63.7491
(5) 40 CFR 63.7495(a), (d), (f)
(6) 40 CFR 63.7499
(7) 40 CFR 63.7500(a)(1), (a)(3), (e)
(8) 40 CFR 63.7501
(9) 40 CFR 63.7505(a)
(10) 40 CFR 63.7510(i)
(11) 40 CFR 63.7515(d)
(12) 40 CFR 63.7530 (e)
(13) 40 CFR 63.7540(a)(10), (a)(13), (b), (d)
(14) 40 CFR 63.7545(a), (c), (e)(1), (e)(6), (e)(7), (e)(8), (i), (h)
(15) 40 CFR 63.7550(a), (c), (h)
(16) 40 CFR 63.7555(a)
(17) 40 CFR 63.7560
(18) 40 CFR 63.7565
(19) 40 CFR 63.7570
(20) 40 CFR 63.7575
(21) Table 3 to Subpart DDDDD of Part 63, items 1, 2 and 3
(22) Table 9 to Subpart DDDDD of Part 63
(23) Table 10 to Subpart DDDDD of Part 63

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

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

New Source Performance Standards (NSPS) Requirements [326 IAC 12][40 CFR 60, Subpart Dc]

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

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

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

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

E.4.2 New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units Requirements [40 CFR Part 60, Subpart Dc] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Dc, the Permittee shall comply with the provisions of New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12, for the natural gas fired auxiliary boiler as specified as follows:

1. 40 CFR 60.40c(a)-(d)
2. 40 CFR 60.41c
3. 40 CFR 60.48c(a)(1), (3)
4. 40 CFR 60.48c(g),(i)

SECTION F [Reserved]

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

ORIS Code: 990

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)

Before Conversion of Boiler number 50 to Natural Gas

(a) One (1) Combustion Engineering Boiler number 50 (also referred to as Unit 5). Boiler 50 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 50. Installation date for Boiler 50 is 1958.

After conversion of Boiler number 50 to Natural Gas

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 (also referred to as Unit 5), constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

Before Conversion of Boiler number 60 to Natural Gas

(b) One (1) Combustion Engineering Boiler number 60 (also referred to as Unit 6). Boiler 60 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of Boiler 60. Installation date for Boiler 60 is 1961.

After conversion of Boiler number 60 to Natural Gas

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 (also referred to as Unit 6), constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 (also referred to as Unit 7). Boiler 70 is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Boiler 7 is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, Boiler 70 exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of Boiler 70. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler number 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(g) One (1) General Electric Gas Turbine Engine number GT4 identified as Unit GT4. Unit GT4 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 875.0 million Btu per hour and exhausting at Stack/Vent ID GT4-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT4 is 1994.

(h) One (1) General Electric Gas Turbine Engine number GT5 identified as Unit GT5. Unit GT5 is a distillate oil fired and/or natural gas fired unit with a design heat input capacity rated at 867.0 million Btu per hour and exhausting at Stack/Vent ID GT5-1. Model number MS 7001. Water injection performed for NOX emission control. Installation date for Unit GT5 is 1995.

(i) One (1) General Electric Gas Turbine Model number PG7241 identified as Unit GT6. Unit GT6 is a natural gas fired unit with a design heat input capacity rated at 1,660 MMBtu per hour and exhausting at Stack/Vent ID GT-6. NOX emissions will be controlled by dry low NOX burners. Installation date for Unit GT6 is 2002.

(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(s), CAIR SO_2 unit(s), and CAIR NO_X ozone season unit(s) subject to this CAIR permit are Boiler 50, Boiler 60 and Boiler 70, Unit GT4, Unit GT5, and Unit GT6.

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 NOX 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.

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), whenever the term "CAIR designated representative" is used, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: Indianapolis Power & Light Company - Harding Street Station.
Source Address: 3700 & 4190 S. Harding St., Indianapolis, Indiana 46217
Part 70 Permit No.: T097-29749-00033

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: Indianapolis Power & Light Company - Harding Street Station.
Source Address: 3700 & 4190 S. Harding St., Indianapolis, Indiana 46217
Part 70 Permit No.: T097-29749-00033

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

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

- The Permittee must notify the Office of Air Quality (OAQ), no later than four (**4**) 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: Indianapolis Power & Light Company - Harding Street Station.
Source Address: 3700 & 4190 S. Harding St., Indianapolis, Indiana 46217
Part 70 Permit No.: T097-29749-00033
Facility: Unit GT4 and Unit GT5
Parameter: Combined Natural Gas and Natural Gas Equivalent usage
Limit: 6300 MMCF per twelve (12) consecutive month period with compliance determined at the end of each month. 1.0 gallon of distillate fuel usage is equivalent to 293 cubic feet of Natural Gas usage.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indianapolis Power & Light Company - Harding Street Station.
Source Address:	3700 & 4190 S. Harding St., Indianapolis, Indiana 46217
Part 70 Permit No.:	T097-29749-00033
Facility:	Unit GT6
Parameter:	NO_X emissions
Limit:	Less than forty (40) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

Submitted by: ______________________________

Title / Position: ______________________________

Signature: ______________________________

Date: ______________________________

Phone: ______________________________

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

Part 70 Quarterly Report

Source Name:	Indianapolis Power & Light Company - Harding Street Station.
Source Address:	3700 & 4190 S. Harding St., Indianapolis, Indiana 46217
Part 70 Permit No.:	T097-29749-00033
Facility:	Units 5, 6, 7 and Auxiliary Boiler
Parameter:	VOC emissions
Limit:	shall not exceed 96.90 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Indianapolis Power & Light Company - Harding Street Station.
Source Address: 3700 & 4190 S. Harding St., Indianapolis, Indiana 46217
Part 70 Permit No.: T097-29749-00033

Months: _________ to ___________ Year: ____________

Page 1 of 2

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 F

Part 70 Operating Permit No: 097-29749-00033

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

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

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

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

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

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

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

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

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

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

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

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

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

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

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

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

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

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

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

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

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

Natural gas means:

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

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

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

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

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

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

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

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

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

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

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

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

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

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

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

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

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

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

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

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

Where:

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

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

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

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

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

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

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

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

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

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

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

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

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

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

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

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

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

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

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{ho} o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} (E_{ao} o). The E_{ho} o is computed using the following formula:

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

Where:

E_{ho} o = Adjusted E_{ho} , ng/J (lb/MMBtu);

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

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

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

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

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

Where:

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

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

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

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g$ o) is computed from E_{ao} o from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai} o) using the following formula:

$$\%R_g^{o} = 100\left(1 - \frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

Where:

$\%R_g$ o = Adjusted $\%R_g$, in percent;

E_{ao} o = Adjusted E_{ao} , ng/J (lb/MMBtu); and

E_{ai} o = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute E_{ai} o, an adjusted hourly SO_2 inlet rate (E_{hi} o) is used. The E_{hi} o is computed using the following formula:

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

Where:

E_{hi} o = Adjusted E_{hi} , ng/J (lb/MMBtu);

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

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$; and

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

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

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

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

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

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

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

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

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

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

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

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

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

(2) Notify the Administrator 1 month before stopping use of the system.

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

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

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

(ii) For O2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

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

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

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

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

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

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

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

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when

calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

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

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

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

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

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

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

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

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

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

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

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

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

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

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

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

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

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

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

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

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

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

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

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

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

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

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

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

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

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

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

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

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

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

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

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

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

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

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

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

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

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Source and Significant Permit Modification

Source Description and Location

Source Name:	Indianapolis Power & Light Company - Harding Street Station
Source Location:	3700 & 4190 S. Harding Street, Indianapolis, IN 46217
County:	Marion
SIC Code:	4911
Operation Permit No.:	T 097-29749-00033
Operation Permit Issuance Date:	August 11, 2011
Significant Source Modification No.:	097-35518-00033
Significant Permit Modification No.:	097-35534-00033
Permit Reviewer:	Josiah Balogun

Existing Approvals

The source was issued Part 70 Operating Permit No. 097-29749-00033 on August 11, 2011. The source has since received the following approvals:

(a) Minor Source Modification No. 097-31154-00033, issued on January 4, 2012;

(b) Minor Permit Modification No. 097-31253-00033, issued on March 22, 2012;

(c) Administrative Amendment No. 097-32557-00033**,** issued on December 5, 2012;

(d) Minor Source Modification No. 097-33349-00033, issued on July 16, 2013; and

(e) Second Administrative Amendment No. 097-33397-00033, issued on July 16, 2013.

(f) Significant Permit Modification No. 097-33122-00033, issued on August 30, 2013;

(g) Significant Source Modification No. 097-33140-00033, issued on September 20, 2013;

(h) Significant Permit Modification No. 097-33352-00033, issued on October 9, 2013;

(i) Significant Permit Modification No. 097-34265-00033, issued on May 12, 2014; and

(j) Administrative Amendment No. 097-35247-00033**,** issued on January 2, 2015.

County Attainment Status

The source is located in Marion County.

Pollutant	Designation
SO_2	Non-attainment effective October 4, 2013, for the Center Township, Perry Township, and Wayne Township. Better than national standards for the remainder of the county.
CO	Attainment effective February 18, 2000, for the part of the city of Indianapolis bounded by 11th Street on the north; Capitol Avenue on the west; Georgia Street on the south; and Delaware Street on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of Indianapolis and Marion County.
O_3	Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard.[1]
$PM_{2.5}$	Attainment effective July 11, 2013, for the annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 24-hour $PM_{2.5}$ standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Unclassifiable or attainment effective December 31, 2011.
[1]Attainment effective October 18, 2000, for the 1-hour ozone standard for the Indianapolis area, including Marion County, and is a maintenance area for the 1-hour ozone National Ambient Air Quality Standards (NAAQS) for purposes of 40 CFR 51, Subpart X*. The 1-hour designation was revoked effective June 15, 2005.	

(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. Marion 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) $PM_{2.5}$
Marion County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) SO_2
U.S. EPA, in the Federal Register Notice 78 FR 47191 dated August 5, 2013, has designated Marion County Perry Township as nonattainment for SO_2. Therefore, SO_2 emissions were reviewed pursuant to the requirements of Emission Offset, 326 IAC 2-3.

(d) Other Criteria Pollutants
Marion County has been classified as attainment or unclassifiable in Indiana for PM10, NO_2, VOC CO and Pb. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a Fossil fuel-fired steam electric plant of more than two hundred fifty million (250,000,000) British thermal units per hour heat input, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Source Status - Existing Source

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

Pollutant	**Emissions** (ton/year)
PM	> 100
PM_{10}	> 100
$PM_{2.5}$	> 100
SO_2	> 100
NO_X	> 100
VOC	> 100
CO	> 100
HAPs	
Single HAP	> 10
Total HAP	> 25

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHGs emissions to determine operating permit applicability or PSD applicability to a source or modification.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant, is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) This existing source is a major stationary source, under Emission Offset (326 IAC 2-3), because SO_2, a nonattainment regulated pollutant, is emitted at a rate of 100 tons per year or more.

(c) These emissions are based upon Part 70 Operating Permit No T 097-29749-00033.

(d) This existing source is a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Indianapolis Power & Light Company - Harding Street Station on February 26, 2015. The proposed change is a modification to Boiler 70 (Unit 7) to enable the unit to use natural gas as its only fuel and discontinue the use of coal and fuel oil. The rated capacity of the unit will increase slightly from 4123 MMBtu/hour to 4346 MMBtu/hour as a result of the proposed change. This modification to Boiler 70 will also allow for the removal of the recently permitted storage silo for activated carbon, which will not be constructed and the source is also proposing to install a new 100 MMBtu/hr natural gas fired auxiliary boiler.
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The following are the list of the proposed new and modified emission units and pollution control device(s):

(a) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(b) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

Emission Units Permitted through Permit No. 097-33140-00033 in 2013:

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 **(also referred to** ~~identified~~ as Unit 5**)**, constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

(b) One (1) 1,162 MMBtu/hr natural gas fired Combustion Engineering Boiler 60 **(also referred to** ~~identified~~ as Unit 6**)**, constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

Note: Boilers 50 and 60 are not being modified as part of this proposed permit modification, but are listed here since they are included in the VOC emission netting analysis along with the new and modified emission units.

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Permit Level Determination – Part 70 Modification to an Existing Source

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency.”

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit. If the control equipment has been determined to be integral, the table reflects the PTE after consideration of the integral control device.

PTE of New Auxiliary Boiler	
Pollutant	**Auxiliary Boiler AB-1 PTE (tons/yr)**
PM	0.82
PM_{10}	3.26
$PM_{2.5}$	3.26
SO_2	0.26
VOC	2.36
CO	16.2
NO_X	15.9
Pb	2.15E-04
Be	5.15E-06
Hg	1.12E-04
Sulfuric Acid Mist	0.002
Fluoride	0
HCl	0
Hexane	0.77
Total HAPs	0.81
CO2e	51,836

PTE Change of the Modified Process (Boiler 70)			
Pollutant	**Unit 7 PTE Before Modification** (ton/yr)	**Unit 7 PTE After Modification** (ton/yr)	**Increase from Modification** (ton/yr)
PM	831	35	0
PM_{10}	28707	142	0
$PM_{2.5}$	17342	142	0
SO_2	95711	11.2	0
VOC	47.5	102.6	55
CO	939	1199	260
NO_X	11881	3807	0
Pb	6.43	0.0093	0
Be	1.03	0.0002	0
Hg	0.2	0.0049	0
Sulfuric Acid Mist	11752	0.86	0
Fluoride	119	0	0
HCl	950.46	0	0
Hexane	0.05	33.59	33.5
Total HAPs	1079.28	35.23	0
CO2e	2953662	2229446	0

Total PTE Increase due to Modification			
Pollutant	**PTE of New Emissions Unit (Aux Boiler AB-1) (tons/yr)**	**Net Increase to PTE of Modified Emission Units (ton/yr)**	**Total PTE for New and Modified Units (Tons/yr)**
PM	0.82	0	0.82
PM_{10}	3.26	0	3.26
$PM_{2.5}$	3.26	0	3.26
SO_2	0.26	0	0.26
VOC	2.36	55	57.36
CO	16.2	260	276.20
NO_X	15.9	0	15.9
Pb	2.15E-04	0	2.15E-04
Be	5.15E-06	0	5.15E-06
Hg	1.12E-04	0	1.12E-04
Sulfuric Acid Mist	0.02	0	0.020
Fluoride	0	0	0
HCl	0	0	0
Hexane	0.77	33.5	34.27
Total HAPs	0.81	0	0.81
CO2e	51,836	0	51,836

This source modification is subject to 326 IAC 2-7-10.5(g)(4)(D) and (g)(7) because the increase in potential to emit of VOC is greater than twenty-five (25) tons per year and the increase in potential to emit of CO is greater than one hundred (100) tons per year before control. Additionally, the modification will be incorporated into the Part 70 Operating Permit through a significant permit modification issued pursuant to 326 IAC 2-7-12(d)(1) because the modification results in emission limit of volatile organic compounds (VOC), and significant changes in existing monitoring, reporting and record keeping requirements of existing Part 70 Permit conditions.

Permit Level Determination – PSD Actual to Projected Actual Test for PM, PM10, PM2.5, SO2, NOx, Co, CO2e, Pb, Hg, Fl

The Permittee has performed Actual to Projected analysis for PSD pollutants PM, PM10, PM2.5, SO2, NOx, CO, CO2e, Pb, Hg, Fl and PSD Netting analysis for VOCs for Boiler 70 and auxiliary boiler for this modification.

The Permittee has provided information as part of the application for this approval that based on Actual to Projected Actual test for existing emission units (pursuant to 326 IAC 2-2-2) this modification at a major stationary source will not be major for Prevention of Significant Deterioration under 326 IAC 2-2-1 because the emission increase of PM, PM10, PM2.5, SO2, NOx, CO, CO2e, Pb, Hg, Fl from the modification is less than the PSD significant levels. IDEM, OAQ has not reviewed this information and will not be making any determination in this regard as part of this approval. The applicant will be required to keep records and report in accordance with Source obligation in 326 IAC 2-2-8.

	Past Actual to Future Projected Actual Analysis for Unit 7 (ton/year)											
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NOx**	**CO**	**CO2e**	**Pb**	**Be**	**Hg**	**H_2SO_4**	**Fl**
Baseline Actual Emissions	1473	7668	7476	1098	2657	856	3162523	1.5E-01	2.5E-02	4.9E-03	9937	100.5
Future Projected Actual Emissions	30	119	119	9	3198	1007	1872735	7.8E-03	1.9E-04	4.1E-03	0.72	0
Emissions that could have been accommodated	3.48	13.9	13.9	1.10	712	289	218703	9.2E-04	2.2E-05	4.8E-04	0.084	0
Actual to Projected Actual Emissions	0	0	0	0	0	0	0	0	0	0	0	0

In determining the baseline emissions from Unit 7, the source has used three separate 24-consecutive month baseline periods including: the period from October 1, 2012 through September 30, 2014 for NOx emissions; the period from February 1, 2011 through January 31, 2013 for CO; and the period from October 1, 2011 through September 30 2013 for all other NSR regulated pollutants. All three of these periods satisfy the time frame requirement since they are within five years of when the permit application was received.

	Potential to Emit (Tons Per Year)											
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NOx**	**CO**	**CO2e**	**Pb**	**Be**	**Hg**	**H_2SO_4**	**Fl**
Actual to Projected Actual Emissions	0	0	0	0	0	0	0	0	0	0	0	0
Auxiliary Boiler AB-1	0.82	3.26	3.26	0.26	15.9	16.2	51,836	2.15E-04	5.15E-06	1.1E-04	0.020	0
ATPA	0.82	3.26	3.26	0.26	15.9	16.2	51,836	2.15E-04	5.15E-06	1.1E-04	0.020	0
Significant Thresholds	**25**	**15**	**10**	**40**	**40**	**100**	**75000**	**0.6**	**0.004**	**0.1**	**7**	**3**

This modification to Boiler 7 to an existing major PSD stationary source is not major for , PM, PM10, PM2.5, NOx, CO, Pb, Hg, Fl because:

(a) The emissions increase of each of these PSD regulated pollutants, PM, PM10, PM2.5, NOx, CO, Pb, Hg, Fl from are less than the PSD significant levels, therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

(b) The emissions increase of GHGs from this modification to an existing major PSD source are less than seventy-five thousand (75,000) tons of CO_2 equivalent (CO_2e) emissions per year. Therefore, GHGs are not subject to regulation and pursuant to 326 IAC 2-2, the PSD requirements do not apply.

(c) This modification to an existing major Emission Offset stationary source is not major because the emissions increase of SO2 is less than the Emission Offset significant levels. Therefore, pursuant to 326 IAC 2-3, the Emission Offset requirements do not apply.

The applicant has proposed a netting analysis for VOC for the propsed modification of Boiler 70 and the new auxiliary boiler. The applicant has proposed a combined limit of VOCs for boilers 50, 60, 70 and the auxiliary boiler to not exceed 96.90 tons per year.

PSD Netting analysis for VOC: Baseline Emissions for VOC

	Baseline Actual Emissions based on November 2012 through October 2014 (Tons per year)
Emission Unit	**VOC**
Boiler 50	9.09
Boiler 60	9.12
Boiler 70	38.7
Auxiliary Boiler	0
Baseline Actual Emissions	56.91

VOC Netting Analysis Table:

Process / Emission Unit	**VOC (Tons/Yr)**
Limited PTE of Boilers 50, 60, and 70 and Auxiliary Boiler	96.90
Baseline Actual Emissions	(56.91)
Contemporaneous Emission Increases	0
Contemporaneous Emission Decrease	0
Net Emissions Increase	**39.99**
PSD Significant Level	**40**

Note: There were no increases or decreases other than those from the project.

The Significant Net Emission increase of VOC is less than the PSD significant level, therefore, pursuant to 326 IAC 2-2, the PSD requirements for VOCs do not apply to Boiler 50, 60, 70 and the Auxiliary Boiler.

Federal Rule Applicability Determination

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the Part 70 major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The new auxiliary boiler has emissions less than the CAM threshold of 100 tons per year for all criteria pollutants, therefore, based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to any of the new and modified units as part of this modification.

The modified unit has CO emissions greater than the CAM threshold of 100 tons per year, but the unit has no control device for CO emission, therefore, based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to the modified unit as part of this modification.

NSPS:

(b) **40 CFR 60, Subpart Da**:
The boiler, identified as Boiler 70 (Unit 7) is not subject to the requirements of New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units (40 CFR 60, Subpart Da), as they were constructed prior to applicability date of September 18, 1978 for this rule. However these standards would applied to these emission units if:

(1) the proposed project is a modification resulting in an increase in emissions of any pollutant to which a standard applies; or

(2) the change is considered a reconstruction as defined in the NSPS rules.

The project does not qualify as a “modification” under the NSPS rules because there will not be an increase in emissions for a pollutant to which a standard applies.

The proposed project does not constitute a reconstruction since the fixed capital cost of the project is less than 50% of the cost of replacing the unit with comparable units.

Since the proposed project does not constitute either modification or reconstruction, the requirements of 40 CFR 60, Subpart Da do not apply to Boiler 70 (Unit 7).

(c) The requirements of the New Source Performance Standard, 40 CFR 60, Subpart Dc, Standard of Performance for Small -Commercial-Institutional Steam Generating Units, which is incorporated by reference as 326 IAC 12 NSPS, applies to steam generating units constructed or modified after June 9, 1989, with heat input equal to or greater than 10 MMBtu/hr but less than or equal to 100 MMBtu/hr [40 CFR 60.40c(a)]. The proposed project will include an auxiliary boiler with a maximum heat input capacity of 100 MMBtu/hr. Since the auxiliary boiler combust natural gas to heat a heat transfer medium, the boilers meet the definition of steam generating units and are regulated by NSPS Dc.

The following emission unit is subject to the following portions of Subpart Dc:

(1) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

The auxiliary boiler is subject to the following Sections of 40 CFR Part 60, Subpart Dc.

1. 40 CFR 60.40c(a)-(d)
2. 40 CFR 60.41c
3. 40 CFR 60.48c(a)(1), (3)
4. 40 CFR 60.48c(g),(i)

(d) There are no New Source Performance Standards (NSPS) (326 IAC 12 and 40 CFR Part 60) included in this proposed modification.

NESHAP:

(e) **40 CFR 63, Subpart DDDDD:**
The natural gas fired boiler, identified as Unit 7 is subject to the requirements of National Emission Standards for Hazardous Air Pollutant (NESHAP) for Industrial, Commercial and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD) after conversion to natural gas, and the auxiliary boiler, identified as AB-1 is also subject to the requirements of this rule which is incorporated by reference as 326 IAC 20-95, since these boilers are located at a major source of HAPs.

The following emission unit is subject to the following portions of Subpart DDDDD:

(1) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(2) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

The two (2) natural gas fired boilers are subject to the following portions of 40 CFR 63, Subpart DDDDD:

(1) 40 CFR 63.7480
(2) 40 CFR 63.7485
(3) 40 CFR 63.7490
(4) 40 CFR 63.7491
(5) 40 CFR 63.7495(a), (d), (f)
(6) 40 CFR 63.7499
(7) 40 CFR 63.7500(a)(1), (a)(3), (e)
(8) 40 CFR 63.7501
(9) 40 CFR 63.7505(a)
(10) 40 CFR 63.7510(i)
(11) 40 CFR 63.7515(d)
(12) 40 CFR 63.7530 (e)
(13) 40 CFR 63.7540(a)(10), (a)(13), (b), (d)
(14) 40 CFR 63.7545(a), (c), (e)(1), (e)(6), (e)(7), (e)(8), (i), (h)
(15) 40 CFR 63.7550(a), (c), (h)
(16) 40 CFR 63.7555(a)
(17) 40 CFR 63.7560
(18) 40 CFR 63.7565

(19) 40 CFR 63.7570
(20) 40 CFR 63.7575
(21) Table 3 to Subpart DDDDD of Part 63, items 1, 2 and 3
(22) Table 9 to Subpart DDDDD of Part 63
(23) Table 10 to Subpart DDDDD of Part 63

Note: Updated version of 40 CFR 63, Subpart DDDDD

(f) **<u>40 CFR 63, Subpart UUUUU:</u>**
The current facility is a major source of HAPs and is subject to the requirements of National Emission Standards for Hazardous Air Pollutants: Coal- And Oil-Fired Electric Utility Steam Generating Units (40 CFR 63, Subpart UUUUU) as long as the source is firing coal as of April 16, 2016 (Consistent with the approved extension). After the proposed modification i.e. conversion of Boiler 70 to natural gas, Boiler 70 will no longer be subject to these standards in accordance with 40 CFR 63.9983(b).

(g) There are no other National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included in this proposed modification.

State Rule Applicability Determination

The following state rules are applicable to the source due to the modification:

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))
This source is a major source for PSD because the potential to emit of one of the regulated pollutants are emitted at a rate greater than 100 tons per year and is in 1 of 28 source categories. The net emission increase from this modification is greater than 40 tons per year for VOC emissions. In order to make the requirements of 326 IAC 2-2 (PSD) not applicable to the 2015 modification, the Permittee has taken the following limits:

(a) The combined PTE for Boiler 50, Boiler 60, Boiler 70 and the auxiliary boiler are greater than 40 tons per year and the Permittee has perform netting analysis for the modification to be a minor modification under PSD review. In netting analysis the increase in the project is determined by calculating emissions from the PTE to BAE. Therefore, the Permittee has taken a limit on combined VOC emissions from the Boiler 50, Boiler 60, (approved in 2013 for modification), Boiler 70 (approved in 2015 for modification) and the auxiliary boiler (approved in 2015 for construction) to not exceed 96.90 tons per twelve (12) consecutive month period, with compliance determined at the end of each month. Therefore, this limit has been determined to be the PTE for all the boilers for significant increase in emissions.

Compliance with this limit, will ensure that the net VOC emissions from Boiler 50, Boiler 60, Boiler 70 and the auxiliary boiler are less than 40 tons per year and renders the requirements of 326 IAC 2-2 (PSD) not applicable to the Boiler 50, Boiler 60, (approved in 2013 for modification) Boiler 70 (approved in 2015 for modification) and the auxiliary boiler (approved in 2015 for construction).

(b) **VOC Emissions Compliance Determination:**

$$\text{VOC emissions (tons/month)} = \{(EFng * P_{U5}) + (EFng * P_{U6}) + (EFng * P_{U7}) + (EFng * P_{AB})\} / 2000 \text{ lbs/ton}$$

Where:

EFng = Emission Factor for natural gas combustion, based on either the AP-42 factor of 0.0054 lbs/MMBtu or the results of the most recent valid stack test on a particular unit for VOCs.

P_{U5} = MMBtu fired for the month for Boiler 50.

P_{U6} = MMBtu fired for the month for Boiler 6.

P_{U7} = MMBtu fired for the month for Boiler 7.

P_{AB} = MMBtu fired for the month for the auxiliary boiler.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of the boiler, identified as Boiler 70 has the potential emit greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs), but the boiler is not subject to the requirements of 326 IAC 2-4.1, because pursuant to 326 IAC 2-4.1(a), the unit is neither being constructed or reconstructed and this Unit is specifically regulated by National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources: Industrial, Commercial and Institutional Boilers and process Heaters NESHAP 40 CFR 63, Subpart DDDDD, which was issued pursuant to Section 112(d) of the CAA. Therefore, pursuant to 326 IAC 2-4.1 (b)(1), boiler 70 is not subject to the requirements of 326 2-4.1.

326 IAC 2-7-6(5) (Annual Compliance Cerification)
The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certification that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

326 IAC 6.5 (Particulate Matter Limitations except Lake County) Unit 5 & 6
Pursuant to 326 IAC 6.5-1-1(b), Particulate limitations shall not be established for combustion units that burns only natural gas at sources or facilities specified in 326 IAC 6.5-6-23.1 as long as the units continues to burn natural gas only. Therefore, Boiler 70 and Unit AB-1 are not subject to the requirements of 326 IAC 6.5.

326 IAC 7-1.1-1 (Sulfur Dioxide Emission Limitations)
(a) The boiler, identified as Unit 7 (Boiler 70) after conversion to natural gas does not have the potential to emit sulfur dioxide of twenty five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. Therefore, the requirements of 326 IAC 7-1.1-1 does not apply to boiler 70 after conversion to natural gas.

(b) The auxiliary boiler, identified as Unit AB-1 does not have the potential to emit sulfur dioxide of twenty five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. Therefore, the requirements of 326 IAC 7-1.1-1 does not apply to Unit AB-1.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)
(a) The uncontrolled potential to emit VOCs from boiler 70 is greater than 25 tons per year, but this unit is constructed prior to 1971 which is before January 1, 1980. Therefore, boiler 70 is not subject to the requirements of 326 IAC 8-1-6.

(b) The uncontrolled potential to emit VOCs from auxiliary boiler, identified as Unit AB-1 is less than 25 tons per year. Therefore, the auxiliary boiler, identified as Unit AB-1 is not subject to the requirements of 326 IAC 8-1-6.

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.

There are no new Compliance Determination and Monitoring Requirements applicable to this source during this modification.

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. T 097-29749-00033. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Change 1: The new emission units have been added to Section A.2 of the permit accordingly.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

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

****

Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 **(also referred to** ~~identified~~ as Unit 7**)**. ~~Unit~~ **Boiler** 7**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. ~~Unit~~ **Boiler** 7**0** is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, ~~Unit~~ **Boiler** 7**0** exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 7**0**. Construction was commenced on ~~Unit~~ **Boiler** 7**0** prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

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(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

Change 2: The activated carbon storage silo that was never constructed by the source has been removed from Section A.3 of the permit accordingly.

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):

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~~(j) One (1) activated carbon storage silo, identified as EU-7ACI, approved for construction in 2013, with a maximum hourly throughput of 1,337 lbs/hour, controlled by a fabric dust collector, identified as ACI-1, and exhausting to stack S-ACI1.~~

Change 3: Section D.3 and its conditions have been modified to include the conversion of Boiler 70 to natural gas only boiler.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 **(also referred to** ~~identified~~ as Unit 7**)**. ~~Unit~~ **Boiler** 7**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. ~~Unit~~ **Boiler** 7 is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, ~~Unit~~ **Boiler** 7**0** exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 7**0**. Construction was commenced on ~~Unit~~ **Boiler** 7**0** prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler number 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

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(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

(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.1.0 **Prevention of Significant Deterioration (PSD) Minor Limits and** Conversion of Existing Operation for Boiler 50 ~~&~~ Boiler 60 **and Boiler 70** to Natural Gas [326 IAC 2-2]

(a) After the startup of Boiler 50 & Boiler 60 to natural gas, the Permittee shall discontinue the use of coal in Boiler 50 & Boiler 60~~, identified as Unit 5 & Unit 6~~.

(b) Within thirty (30) days after the date Boiler 50 & Boiler 60 are converted to natural gas, the Permittee shall provide a notification to IDEM indicating the date Boiler 50 & Boiler 60 were converted to natural gas.

(c) After the startup of Boiler 70 on natural gas, the Permittee shall discontinue the use of coal in Boiler 70.

(d) Within thirty (30) days after the date Boiler 70 is converted to natural gas, the Permittee shall provide a notification to IDEM indicating the date Boiler 70 was converted to natural gas.

(e) The combined VOC emissions from the Boiler 50, Boiler 60, (approved in 2013 for modification) Boiler 70 (approved in 2015 for modification) and the auxiliary boiler (approved in 2015 for construction) shall not exceed 96.90 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit, will ensure that the net VOC emissions from Boiler 50, Boiler 60, Boiler 70 and the auxiliary boiler are less than 40 tons per year and renders the requirements of 326 IAC 2-2 (PSD) not applicable to the Boiler 50, Boiler 60, (approved in 2013 for modification) Boiler 70 (approved in 2015 for modification) and the auxiliary boiler (approved in 2015 for construction).

(f) Condition D.1.0(e) shall be effective after the conversion of Boiler 50, 60 and 70 to natural gas.

D.1.1 Marion County [326 IAC 6.5-6][326 IAC 2-7-5]

(a) Pursuant to 326 IAC 6.5-6 (Marion County), the Permittee shall comply with the following emission limitations for particulate (PM):

Unit ID	PM Limit (pounds PM per million Btu)	PM Limit (tons per year)
~~Unit 5 (~~Boiler number 50~~)~~	0.135	82.2
~~Unit 6 (~~Boiler number 60~~)~~	0.135	82.2
~~Unit 7 (~~Boiler number 70~~)~~	0.10	830.7
Unit GT1 (Gas Turbine GT1)	0.015	0.28
Unit GT2 (Gas Turbine GT2)	0.015	0.28

****

(c) Condition D.1.1 shall cease to apply to Boiler 50 & Boiler 60 (Unit 5 & Unit 6) after Boiler 50 & Boiler 60 are converted to ~~Natural Gas~~ **natural gas**.

(d) Condition D.1.1 shall cease to apply to Boiler 70 after Boiler 70 is converted to natural gas.

D.1.2 Sulfur Dioxide (SO_2) Emission Limitations: Marion County [326 IAC 7-4-2]

(a) Pursuant to 326 IAC 7-4-2 (Sulfur Dioxide Emission Limitations: Marion County), the Permittee shall comply with the following emission limitations in pounds per million Btu:

Unit ID	SO_2 Limit (pounds per million Btu)
~~Unit 5 and Unit 6~~ ~~(~~Boiler number 50 and Boiler number 60~~)~~	4.7

Unit ID	SO_2 Limit (pounds per million Btu)
~~Unit 7~~ ~~(~~Boiler number 70~~)~~	5.3
Unit GT1 and Unit GT2 (Gas Turbines GT1 and GT2)	0.35

(b) As an alternative to the emission limitations listed above, pursuant to 326 IAC 7-4-2, Unit 5, 6 and Unit GT1 and GT2 may comply with any one (1) of the sets of alternative emission limitations in pounds per million Btu as follows:

Alternative Scenario	Unit ID	SO_2 Limit (pounds per million Btu)
1	~~Unit 5 and Unit 6~~ ~~(~~Boiler number 50 and Boiler number 60~~)~~	5.2
	Unit GT1 and GT2 (Gas Turbines GT1 and GT2)	0.0
2	~~Unit 5 and Unit 6~~ ~~(~~Boiler number 50 and Boiler number 60~~)~~	5.0
	Unit GT1 and GT2 (Gas Turbines GT1 and GT2)	0.4
3	~~Unit 5 and Unit 6~~ ~~(~~Boiler number 50 and Boiler number 60~~)~~	4.1
	Unit GT1 and GT2 (Gas Turbines GT1 and GT2)	0.3
4	~~Unit 5 and Unit 6~~ ~~(~~Boiler number 50 and Boiler number 60~~)~~	3.9
	GT1 and GT2 (Gas Turbines GT1 and GT2)	0.35

****

(c) Condition D.1.2 **-** Sulfur Dioxide (SO_2) Emission Limitations, shall not apply to Boiler 50~~,~~ & Boiler 60 after Boiler 50, & Boiler 60 are converted to **natural gas** ~~Natural Gas~~.

(d) Condition D.1.2 - Sulfur Dioxide (SO_2) Emission Limitations, shall not apply to Boiler 70 after Boiler 70 is converted to natural gas.

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D.1.4 Startup, Shutdown and Other Opacity Limits [326 IAC 5-1-3(e)(2)] [326 IAC 5-1-3(b)]

(a) Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), the following applies to ~~Unit 5, Unit 6~~ **Boiler 50, Boiler 60** and ~~Unit 7~~ **Boiler 70** Bypass Stack:

(1) When building a new fire in ~~Unit 5 or Unit 6~~ **Boiler 50 or Boiler 60**, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of twenty-five (25) six (6)-minute averaged periods (2.5 hours) during the startup period, or until the flue gas temperature entering the electrostatic precipitator reaches two hundred and fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitator, whichever occurs first. [326 IAC 5-1-3(e)(2)]

(2) When building a new fire in ~~Unit 7~~ **Boiler 70** Bypass Stack, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of fifty (50) six (6)-minute averaged periods (5.0 hours) during the startup period, or until the flue gas temperature entering the electrostatic precipitator reaches two hundred and fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitator, whichever occurs first. [326 IAC 5-1-3(e)(2)]

(3) When shutting down **Boiler 50, Boiler 60** and/or ~~Unit 7~~ **Boiler 70** Bypass Stack, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of ten (10) six (6)-minute averaging periods (1.0 hours) for each Unit.
[326 IAC 5-1-3(e)(2)]

****

(d) Condition D.1.4(a), (b) and (c) - Temporary Alternative Opacity Limitations, shall not apply to Boiler 50 & Boiler 60 after Boiler 50, & Boiler 60 are converted to **natural gas** ~~Natural Gas~~.

(e) Condition D.1.4(a), (b) and (c) - Temporary Alternative Opacity Limitations, shall not apply to Boiler 70 after Boiler 70 is converted to natural gas.

Compliance Determination Requirements

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

****

(b) Condition D.1.5 - Testing Requirements, shall not apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to Natural Gas.

(c) Condition D.1.5 - Testing Requirements, shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.5.1 VOC Emissions Compliance Determination Requirements [326 IAC 2-2]

(a) In order to determine compliance status with Condition D.1.0(e) - Prevention of Significant Deterioration (PSD) Minor Limits and Conversion of Existing Operation for Boiler 50, Boiler 60 and Boiler 70 to Natural Gas, the Permittee will determine the VOC emissions using the following equation:

$$\textbf{VOC emissions (tons/month)} = \{(EFng * P_{U5}) + (EFng * P_{U6}) + (EFng * P_{U7}) + (EFng * P_{AB})\} / 2000 \text{ lbs/ton}$$

Where:

EFng = Emission Factor for natural gas combustion, based on either the AP-42 factor of 0.0054 lbs/MMBtu or the results of the most recent valid stack test on a particular unit for VOCs.

P_{U5} = MMBtu fired for the month for Boiler 50.

P_{U6} = MMBtu fired for the month for Boiler 60.

P_{U7} = MMBtu fired for the month for Boiler 70.

P_{AB} = MMBtu fired for the month for the auxiliary boiler.

(b) Condition D.1.5.1(a) shall be effective after the conversion of Boiler 50, Boiler 60 and Boiler 70 to natural gas.

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

(a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitators (ESPs) shall be operated at all times that Boilers 50, 60 and 70, ~~identified as Unit 5, 6 and 7,~~ are in operation.

(b) Condition D.1.6 Operation of Electrostatic Precipitator, shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to ~~Natural Gas~~ **natural gas**.

(c) Condition D.1.6 Operation of Electrostatic Precipitator, shall not apply to Boiler 70

after the conversion of Boiler 70 to natural gas.

D.1.7 Continuous Monitoring of Emissions [326 IAC 3-5][40 CFR 64]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous opacity monitoring systems for ~~Unit 5, Unit 6 and Unit 7~~ **Boiler 50, Boiler 60 and Boiler 70** Bypass Stack shall be calibrated, maintained, and operated for measuring opacity, which meets the performance specifications of 326 IAC 3-5-2.

(b) Pursuant to Commissioner's Order #2008-02, in lieu of the requirement to monitor opacity in the stack exhaust from the scrubbed stack of ~~Unit 7~~ **Boiler 70**, in accordance with 326 IAC 3-5-1(c)(2)(A), the Permittee shall comply with the following alternative monitoring plan.

****

(c) Condition D.1.7 - Continuous Monitoring of Emissions, shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to ~~Natural Gas~~ **natural gas**.

(d) Condition D.1.7 - Continuous Monitoring of Emissions, shall not apply Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.8 Sulfur Dioxide Emissions (SO_2) and Sulfur Content [326 IAC 7-2][326 IAC 7-4-2]

Compliance for Unit 5, Unit 6 and Unit 7 shall be determined as follows:

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of the SO_2 limitation(s) in pounds per million Btu for ~~Unit 5, Unit 6 and Unit 7~~ **Boiler 50, Boiler 60 and Boiler 70** stated in Condition D.1.2, using a thirty (30) day rolling weighted average.

****

(c) Condition D.1.8(a) and (b), shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to natural Gas.

(d) Condition D.1.8(a) and (b), shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

****

D.1.10 Compliance Schedule for National Emission Standard for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR 63, Subpart UUUUU]

Pursuant to Indiana Code § 13-14-6 and in order to secure compliance with 40 CFR 63, Subpart UUUUU, Indianapolis Power & Light Company, Harding Street is subject to the following order:

(1) Indianapolis Power & Light Company shall submit a status report with fifteen (15) days of completion of the following milestones indicating the actual dates of completion:

(a) The dates on-site construction of new generation or conversion to firing natural gas identified in Attachment E for Harding Street ~~Units~~ **Boilers** 5**0** and 6**0** are initiated, and

(b) The date on-site construction of new generation or conversion to firing natural gas identified in Attachment E for Harding Street ~~Units~~ **Boilers** 5**0** and 6**0** are completed.

(c) The dates on-site construction for the installation of the emission control equipment and upgrades identified in Attachment E for Harding Street ~~Unit~~ **Boiler** 7**0** are initiated, and

(d) The dates on-site construction for the installation of the emission control equipment and upgrades identified in Attachment E for Harding Street ~~Unit~~ **Boiler** 7**0** are completed.

(e) The dates by which final compliance with 40 CFR 63, Subpart UUUUU for Harding Street ~~Units~~ **Boilers** 5**0**, 6**0** and 7**0** are achieved.

(2) ~~Units~~ **Boiler** 5**0**, 6**0** and 7**0** shall comply with the standards set forth in 40 CFR 63, Subpart UUUUU no later than April 16, 2016.

(3) Condition D.1.10(1) and (2), shall not apply to Boiler 50, and Boiler 60 after the conversion of Boiler 50, and Boiler 60 to natural gas.

(4) Condition D.1.10(1) and (2), shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

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

D.1.11 Electrostatic Precipitator Parametric Monitoring [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)][40 CFR 64]

****

(d) Condition ~~D.1.10~~ **D.1.11 -** Electrostatic Precipitator Parametric Monitoring, shall not apply to Boiler 50, & Boiler 60 after the conversion of Boiler 50, & Boiler 60 to natural Gas.

(e) Condition D.1.11 - Electrostatic Precipitator Parametric Monitoring, shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.12 Opacity Readings [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) Except during periods of startup and shutdown, appropriate response steps shall be taken whenever opacity exceeds twenty-five percent (25%) for three (3) consecutive six (6) minute averaging periods for ~~Unit 5~~ **Boiler 50** or ~~Unit 6~~ **Boiler 60**. Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty five percent (25%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Except during periods of startup and shutdown, appropriate response steps will be taken whenever opacity exceeds twenty percent (20%) for three (3) consecutive six (6) minute averaging periods for ~~Unit 7~~ **Boiler 70** Bypass Stack. Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

****

(e) Condition ~~D.1.11~~ **D.1.12** - Opacity Readings, shall no longer apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to natural Gas.

(f) Condition D.1.12 - Opacity Readings, shall no longer apply Boiler 70 after the conversion of Boiler 70 to natural Gas.

****

D.1.14 NOx and SO_2 Continuous Emission Monitoring Systems [326 IAC 2-7-6][326 IAC 2-7-5(3)][40 CFR 75]

(a) The Permittee shall install, certify, calibrate, maintain and operate continuous emission monitoring systems (CEMS) and related equipment measuring NOx and SO_2 emissions from ~~Unit 5, Unit 6 and Unit 7~~ **Boiler** 5**0**, **Boiler 60 and Boiler** 7**0**.

****

(b) Whenever the SO_2 continuous emission monitoring systems (CEMS) on ~~Units 5~~ **Boiler** 5**0** or ~~6~~ **Boiler** 6**0** is malfunctioning or down for repairs or adjustments and a backup CEMS is not brought on-line for more than 24 hours, the following shall be used to

provide information related to SO_2 emissions:
****

(c) Whenever the SO_2 continuous emissions monitoring system (CEMS) on ~~Unit 7~~ **Boiler** 7**0** is malfunctioning or down for repairs or adjustment and a backup CEMS is not brought on-line, the following shall be used to provide information related to SO_2 emissions:
****

(d) Condition ~~D.1.13~~ **D.1.14**(b)**,** shall not apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to natural Gas.

(e) Condition D.1.14(c), shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.15 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 2-7-5(3)(A)]

****

(b) Whenever ~~Unit 7~~ **Boiler 70** exhausts to the scrubbed stack and this particulate (PM) continuous emission monitoring system (CEMS) is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used to provide information related to particulate emissions:

(1) The ability of the FGD to control particulate matter emissions shall be monitored once per day when ~~Unit 7~~ **Boiler 70** is in operation by measuring and recording the following:
****

(c) Condition D.1.15 shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

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

D.1.16 Record Keeping Requirements

(a) To document the compliance status with Section C - Opacity and Conditions D.1.1, D.1.4, D.1.5, D.1.11, and D.1.15, the Permittee shall maintain records in accordance with (1) through (8) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C – Opacity and Conditions D.1.1 and D.1.4:
****

(3) PM continuous emissions monitoring data associated with ~~Unit 7~~ **Boiler 70** scrubbed stack as required in Condition D.1.15.
****

(7) To document the compliance status with Condition D.1.11, the Permittee shall maintain a daily record of the primary and secondary voltages and the current readings of the transformer-rectifier sets of the electrostatic precipitators, identified as Control Equipment ID CE 50 and Control Equipment ID CE 60, controlling emissions from ~~Unit 5~~ **Boiler 50** and ~~Unit 6~~ **Boiler 60**, respectively. The Permittee shall include in its daily record when the primary and secondary voltage and current readings are not taken and the reason for the lack of primary and secondary voltage and current readings (e.g. the process did not operate that day).

(8) To document the compliance status with D.1.15, the Permittee shall maintain a record of the number of recycle pumps in service and the absorber pH associated with the FGD when ~~Unit 7~~ **Boiler 70** exhausts to the scrubbed stack and PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more and a backup CEMS is not brought on-line. On days when ~~Unit 7~~ **Boiler 70** exhausts to the scrubbed stack and PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more and a backup CEMS is not brought on-line, the Permittee shall include in its record when readings are not taken and the reason for the lack of readings. (e.g. the boiler did not operate that day.)

(b) To document the compliance status with Condition D.1.2, D.1.8 and D.1.14, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the SO_2 limit established in Condition D.1.2 for ~~Unit 5, Unit 6 and Unit 7~~ **Boiler** 5**0**, **Boiler 60 and Boiler** 7**0**.
****

(f) Condition**s** ~~D.1.15(a)(7)~~ **D.1.16(a)(4), (a)(6), and (a)(7)** - Recordkeeping Requirements, shall not apply to Boiler 50 & Boiler 60 after the conversion of Boiler 50 & Boiler 60 to Natural Gas.

(g) Conditions D.1.16(a)(3), (a)(4), (a)(6), (a)(7) and (a)(8) shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

D.1.17 Reporting Requirements

(a) A quarterly report of opacity exceedances, continuous emission monitor exceedances, a quarterly summary of ~~Unit 7~~ **Boiler 70** PM emissions, and a quarterly summary of the information to document compliance status with Conditions D.1.14 shall be submitted no later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee'ss obligation with regard to the reporting required by this condition. 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(35).

(b) A quarterly summary of the information to document the compliance status with Condition D.1.0(e) shall be submitted to the address listed in Section C- General Reporting Requirements, of this permit, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

(c) Condition D.1.17(a) shall not apply to Boiler 70 after the conversion of Boiler 70 to natural gas.

Change 4: The activated carbon and its conditions have been removed from Section D.7 of the permit accordingly.

SECTION D.7 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(14)]:

<u>Insignificant Activities</u>

****
~~(j) One (1) activated carbon storage silo identified as EU-7ACI, approved for construction in 2013, with a maximum hourly throughput of 1,337 lbs/hour, controlled by a fabric filter dust collector, identified as ACI-1 and exhausting to stack S-ACI1.~~

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

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

D.7.1 Particulate Matter Limitations Except Lake County [326 IAC 6.5]

(a) **

~~(c) Pursuant to 326 IAC 6.5-1-1(b), particulate matter (PM) emissions from EU-7ACI shall not exceed three hundredths (0.03) grains per dry standard cubic feet.~~
****

D.7.3 Material requirements for cold cleaner degreasers [326 IAC 8-3-8]

(a) **

~~(c) Record keeping requirements are as follows:~~

~~(1) All persons subject to the requirements of subsection (b)(1) shall maintain all of the following records for each sale:~~

~~(A) The name and address of the solvent purchaser.~~

~~(B) The date of sale (or invoice/bill date of contract servicer indicating service date).~~

~~(C) The type of solvent sold.~~

~~(D) The volume of each unit of solvent sold.~~

~~(E) The total volume of the solvent sold.~~

~~(F) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).~~

~~(2) All persons subject to the requirements of subsection (b)(2) shall maintain each of the following records for each purchase:~~

~~(A) The name and address of the solvent supplier.~~

~~(B) The date of purchase (or invoice/bill date of contract servicer indicating service date).~~

~~(C) The type of solvent purchased.~~

~~(D) The total volume of the solvent purchased.~~

~~(E) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).~~

~~(d) All records required by subsection (c) shall be:~~

~~(1) retained on-site or accessible electronically from the site for the most recent three (3) year period; and~~

~~(2) reasonably accessible for an additional two (2) year period.~~

~~Compliance Determination Requirements~~

~~D.7.4 Particulate Control [326 IAC 2-7-6(6)]~~

~~In order to ensure compliance with the particulate matter emissions limits specified in Condition D.7.1(c), the silo fabric filter dust collector shall be in operation and controlling emissions whenever the equipment is in operation.~~

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

~~D.7.5 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]~~

~~(a) Visible emission notations of the activated carbon storage silo identified as EU-7ACI shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.~~

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

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

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

~~(e) If abnormal emissions are observed from Unit EU-7ACI stack exhaust (S-ACI1), the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.~~

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

D.7.~~6~~**4** Record Keeping Requirements

(a) Record keeping requirements are as follows:

(1) All persons subject to the requirements of subsection (b)(1) shall maintain all of the following records for each sale:

(A) The name and address of the solvent purchaser.
(B) The date of sale (or invoice/bill date of contract servicer indicating service date).
(C) The type of solvent sold.
(D) The volume of each unit of solvent sold.
(E) The total volume of the solvent sold.
(F) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

(2) All persons subject to the requirements of subsection (b)(2) shall maintain each of the following records for each purchase:

(A) The name and address of the solvent supplier.
(B) The date of purchase (or invoice/bill date of contract servicer indicating service date).
(C) The type of solvent purchased.
(D) The total volume of the solvent purchased.
(E) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

(b) All records required by subsection (c) shall be:

(1) retained on-site or accessible electronically from the site for the most recent three (3) year period; and
(2) reasonably accessible for an additional two (2) year period.

~~(a) To document the compliance status with Condition D.7.5 - Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations from Activated Carbon storage silo, identified as EU-7ACI. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation (e.g. the process did not operate that day).~~

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

Change 5: The two new boilers have been added to Section E.3 of the permit accordingly.

After the Conversion of Boiler number 50 & 60 & 70 to Natural Gas

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 **(also referred to as** ~~identified as~~ Unit 5**)**, constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

(b) One (1) 1,162 MMBtu/hr natural gas fired Combustion Engineering Boiler 60 **(also referred to as** ~~identified as~~ Unit 6**)**, constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to

natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.3.1 General Provisions Relating to NESHAP [326 IAC 20-1][40 CFR Part 63, Subpart A]

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

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

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

E.3.2 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD] [326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR 63, Subpart DDDDD, (included as Attachment D of this permit), which are incorporated by reference as 326 IAC 20-95, except as otherwise specified in 40 CFR 63, Subpart DDDDD:

(1) 40 CFR 63.7480
(2) 40 CFR 63.7485
(3) 40 CFR 63.7490
(4) 40 CFR 63.7491
(~~4~~**5**) 40 CFR 63.7495(~~b~~**a**), (d), (f)
(~~5~~**6**) 40 CFR 63.7499~~(l)~~
(~~6~~**7**) 40 CFR 63.7500(a)(1), (a)(3), (e)
(~~7~~**8**) 40 CFR 63.7501
(~~8~~**9**) 40 CFR 63.7505(a)
(~~9~~**10**) 40 CFR 63.7510(i)
(~~9~~**11**) 40 CFR 63.7515(d)
(~~10~~**12**) 40 CFR 63.7530 (e)
(~~1~~1**3**) 40 CFR 63.7540(a)(10), (a)(13), (b), (d)
(~~12~~**14**) 40 CFR 63.7545(a), (~~b~~**c**), **(e)(1), (e)(6), (e)(7), (e)(8), (i),** (h)
(~~13~~**15**) 40 CFR 63.7550(a), ~~(b),~~ (c), (h)~~(3)~~
(~~14~~**16**) 40 CFR 63.7555(a)
(~~15~~**17**) 40 CFR 63.7560
(~~16~~**18**) 40 CFR 63.7565
(~~17~~**19**) 40 CFR 63.7570
(~~18~~**20**) 40 CFR 63.7575
(~~19~~**21**) Table 3 to Subpart DDDDD of Part 63, items 1, 2 and 3
(~~20~~**22**) Table 9 to Subpart DDDDD of Part 63

(~~21~~**23**) Table 10 to Subpart DDDDD of Part 63

Change 6: A new Section E.4 has been added to the permit to include the 40 CFR 60, Subpart Dc for the auxiliary boiler.

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: **(t) One (1) natural gas-fired auxiliary boiler, identified as Unit AB-1, with a rated capacity of 100 MMBtu/hour, approved in 2015 for construction, equipped with low NOx burners and exhausting to stack AB-1.** (The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 12][40 CFR 60, Subpart Dc]

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

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

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

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

E.4.2 New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units Requirements [40 CFR Part 60, Subpart Dc] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Dc, the Permittee shall comply with the provisions of New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12 (Included in Attachment F of the permit), for the natural gas fired auxiliary boiler as specified as follows:

1. 40 CFR 60.40c(a)-(d)
2. 40 CFR 60.41c
3. 40 CFR 60.48c(a)(1), (3)
4. 40 CFR 60.48c(g),(i)

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

Part 70 Quarterly Report

Source Name: **Indianapolis Power & Light Company - Harding Street Station.**
Source Address: **3700 & 4190 S. Harding St., Indianapolis, Indiana 46217**
Part 70 Permit No.: **T097-29749-00033**

Facility: **Units 5, 6, 7 and Auxiliary Boiler**
Parameter: **VOC emissions**
Limit: **shall not exceed 96.90 tons per twelve (12) consecutive month period with compliance determined at the end of each month.**

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

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

Additional Changes

IDEM, OAQ has decided to make additional revisions to the permit as described below, with deleted language as ~~strikeouts~~ and new language **bolded**.

Change 1: All the emission descriptions in Sections A.2, D.1, D.3, E.1, E.3 and Section G have been revised in throughout the permit accordingly.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

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

Before Conversion of Boiler number 50 to Natural Gas

(a) One (1) Combustion Engineering Boiler number 50 **(also referred to** ~~identified~~ as Unit 5**)**. ~~Unit~~ **Boiler** 5**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 5**0**. Installation date for ~~Unit~~ **Boiler** 5**0** is 1958.

After Conversion of Boiler number 50 to Natural Gas

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 **(also referred to** ~~identified~~ as Unit 5**)**, constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

Before Conversion of Boiler number 60 to Natural Gas

(b) One (1) Combustion Engineering Boiler number 60 **(also referred to** ~~identified~~ as Unit 6**)**. ~~Unit~~ **Boiler** 6**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 6**0**. Installation date for ~~Unit~~ **Boiler** 6**0** is 1961.

After Conversion of Boiler number 60 to Natural Gas

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 **(also referred to** ~~identified~~ as Unit 6**)**, constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 **(also referred to** ~~identified~~ as Unit 7**)**. ~~Unit~~ **Boiler** 7**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. ~~Unit~~ **Boiler** 7**0** is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, ~~Unit~~ **Boiler** 7**0** exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 7**0**. Construction was commenced on ~~Unit~~ **Boiler** 7**0** prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler number 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

(d) One (1) Cooling Tower associated with ~~Unit~~ **Boiler** 7**0**, identified as CT-7, approved for construction in 2012, with a capacity of 189,280 gallons circulating water per minute and maximum drift rate of 0.001%.

****

(k) Coal material handling and storage system with a maximum annual capacity of 7.5 million tons per year and described as follows:

****

(2) One (1) covered conveyor system, constructed in 1931, consisting of the following equipment:
  - (i) No. 2 conveyor which transfers coal from the railcar receiving area to the crusher house;
  - (ii) No. 3 conveyor transfers coal from the crusher to No. 4 conveyor;
  - (iii) No. 4 conveyor transfers coal from the crusher to the cross-over conveyor;
  - (iv) Cross-over conveyor transfers coal from No. 4 conveyor to No. 5 conveyor or to conveyor 705 (which then transfers to conveyor 703 and to Unit 7); and
  - (v) No. 5 conveyor transfers coal from the cross-over conveyor to ~~Unit~~ **Boiler** 5**0** or ~~Unit~~ **Boiler** 6**0**.

****

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Before Conversion of Boiler number 50 to Natural Gas

(a) One (1) Combustion Engineering Boiler number 50 **(also referred to** ~~identified~~ as Unit 5**)**. ~~Unit~~ **Boiler** 5**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 5**0**. Installation date for ~~Unit~~ **Boiler** 5**0** is 1958.

After conversion of Boiler number 50 to Natural Gas

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 **(also referred to** ~~identified~~ as Unit 5**)**, constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

Before Conversion of Boiler number 60 to Natural Gas

(b) One (1) Combustion Engineering Boiler number 60 **(also referred to** ~~identified~~ as Unit 6**)**. ~~Unit~~ **Boiler** 6**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 6**0**. Installation date for ~~Unit~~ **Boiler** 6**0** is 1961.

After conversion of Boiler number 60 to Natural Gas

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 **(also referred to** ~~identified~~ as Unit 6**)**, constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

****

(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)]

****

SECTION E.1 TITLE IV CONDITIONS

Emissions Unit Description:

<u>Before Conversion of Boiler number 50 to Natural Gas</u>

(a) One (1) Combustion Engineering Boiler number 50 **(also referred to** ~~identified~~ as Unit 5**)**. ~~Unit~~ **Boiler** 5**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 5**0**. Installation date for ~~Unit~~ **Boiler** 5**0** is 1958.

<u>After conversion of Boiler number 50 to Natural Gas</u>

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 (also referred to as Unit 5), constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

<u>Before Conversion of Boiler number 60 to Natural Gas</u>

(b) One (1) Combustion Engineering Boiler number 60 **(also referred to** ~~identified~~ as Unit 6**)**. ~~Unit~~ **Boiler** 6**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 6**0**. Installation date for ~~Unit~~ **Boiler** 6**0**is 1961.

<u>After conversion of Boiler number 60 to Natural Gas</u>

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 (also referred to as Unit 6), constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

<u>Before Conversion of Boiler number 70 to Natural Gas</u>

(c) One (1) Combustion Engineering Boiler number 70 **(also referred to** ~~identified~~ as Unit 7**)**. ~~Unit~~ **Boiler** 7**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. ~~Unit~~ **Boiler** 7**0** is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, ~~Unit~~ **Boiler** 7**0** exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 7**0**. Construction was commenced on ~~Unit~~ **Boiler** 7**0** prior to August 17, 1971 and completed in 1973.

<u>After Conversion of Boiler number 70 to Natural Gas</u>

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

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

Acid Rain Program

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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: 990

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)

<u>Before Conversion of Boiler number 50 to Natural Gas</u>

(a) One (1) Combustion Engineering Boiler number 50 **(also referred to** ~~identified~~ as Unit 5**)**. ~~Unit~~ **Boiler** 5**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 50 and exhausting at Stack/Vent ID 5-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 5**0**. Installation date for ~~Unit~~ **Boiler** 5**0** is 1958.

<u>After conversion of Boiler number 50 to Natural Gas</u>

(a) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 50 (also referred to as Unit 5), constructed in 1958, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 5-1.

<u>Before Conversion of Boiler number 60 to Natural Gas</u>

(b) One (1) Combustion Engineering Boiler number 60 **(also referred to** ~~identified~~ as Unit 6**)**. ~~Unit~~ **Boiler** 6**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 1017.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 60 and exhausting at Stack/Vent ID 6-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. Also equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective non-catalytic reduction technology (SNCR). These technologies were voluntarily installed. Distillate fuel oil is used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 6**0**. Installation date for ~~Unit~~ **Boiler** 6**0** is 1961.

After conversion of Boiler number 60 to Natural Gas

(b) One (1) 1,162 MMBtu/hr Combustion Engineering Boiler 60 (also referred to as Unit 6), constructed in 1961, approved for modification in 2013 from coal to natural gas combustion only, and exhausting at Stack/Vent ID 6-1.

Before Conversion of Boiler number 70 to Natural Gas

(c) One (1) Combustion Engineering Boiler number 70 **(also referred to** ~~identified~~ as Unit 7**)**. ~~Unit~~ **Boiler** 7**0** is a pulverized coal tangentially fired unit with a design heat input capacity rated at 4123.0 million Btu per hour. Emissions are directed to one (1) cold side electrostatic precipitator identified as Control Equipment ID CE 70 and exhausting at Stack/Vent ID 7-1. SO3 injection is utilized as a flue gas conditioning agent for the electrostatic precipitator but the source is not required to perform gas conditioning. ~~Unit~~ **Boiler** 7**0** is equipped with low NOX burners, neural net controls, separated overfire air (SOFA), and selective catalytic reduction technology (SCR) and FGD scrubber. These technologies were voluntarily installed. When the FGD is in operation, ~~Unit~~ **Boiler** 7**0** exhausts to a separate wet stack. Distillate fuel oil and used oil are used as supplemental fuel and for firing during startup of ~~Unit~~ **Boiler** 7**0**. Construction was commenced on ~~Unit~~ **Boiler** 7**0** prior to August 17, 1971 and completed in 1973.

After Conversion of Boiler number 70 to Natural Gas

(c) One (1) natural gas-fired Combustion Engineering Boiler number 70 (also referred to as Unit 7), with a rated capacity of 4346 MMBtu/hour approved for conversion from coal to natural gas in 2015. Boiler 70 is equipped with low NOX burners, neural net controls, separated over fire air (SOFA), and selective catalytic reduction technology (SCR). These technologies were voluntarily installed. Construction was commenced on Boiler 70 prior to August 17, 1971 and completed in 1973.

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

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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(s), CAIR SO_2 unit(s), and CAIR NO_X ozone season unit(s) subject to this CAIR permit are ~~Unit 5, Unit 6, Unit 7~~ **Boiler** 5**0**, **Boiler 60 and Boiler** 7**0**, Unit GT4, Unit GT5, and Unit GT6.

Conclusion and Recommendation

The construction and the operation of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 097-35518-00033 and Significant Permit Modification No. 097-35534-00033. The staff recommends to the Commissioner that this Part 70 Significant Source and Significant Permit Modification be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5257 or toll free at 1-800-451-6027 extension 4-5257.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

Appendix A: Emissions Calculations
Emission Summary

Source Name: Indianapolis Power & Light Company - Harding Street Station
Source Location: 3700 & 4190 S. Harding Street
Permit Number: 097-35518-00033
Permit Reviewer: Josiah Balogun
Date: 10-Mar-2015

Uncontrolled Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	NOx (tons/yr)	VOC (tons/yr)	CO (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit									
Auxiliary Boielr AB-1	0.82	3.26	3.26	0.26	15.94	2.36	16.16	51835.63	0.81
Boiler 70	35.46	141.83	141.83	11.20	3807.10	102.64	1199.05	2252776.28	35.22
Total Emissions	36.27	145.10	145.10	11.45	3823.04	105.00	1215.21	2304611.90	36.03

ATPA Table

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	NOx (tons/yr)	CO (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit								
Actual to Projected Actual for Boiler 70	0	0	0	0	0	0	0	0
Auxiliary Boielr AB-1	0.82	3.26	3.26	0.26	15.94	16.16	51835.63	0.81
Total Emissions	0.82	3.26	3.26	0.26	15.94	16.16	51835.63	0.81

Appendix A: Emissions Calculations
Emission Summary

Source Name: Indianapolis Power & Light Company - Harding Street Station
Source Location: 3700 & 4190 S. Harding Street
Permit Number: 097-35518-00033
Permit Reviewer: Josiah Balogun
Date: 10-Mar-2015

The Applicant has proposed a netting analysis for VOC for the propsed modification of Boiler 70 and the new auxiliary boiler.
The Applicant has proposed a combined limit of VOCs for Boilers 50, 60, 70 and auxiliary boiler to not exceed 96.9 tons per twleve consecutive month period, with compiance determined at the end of each month.

PSD Netting Analysis for VOC: Baseline Emissions for VOC

	Baseline Actual Emissions based on November 2012 through October 2014 (Tons per year)
Emission Units	VOC
Boiler 50	9.09
Boiler 60	9.12
Boiler 70	38.7
Auxiliary Boiler	0
Baseline Actual Emissions	56.91

VOC Netting Analysis

Process/Emission Units	**VOC**
Limited PTE of Boilers 50, 60, 70 and Auxiliary Boiler	96.9
Baseline Actual Emissions	-56.91
Contemporaneous Emission Increases	0
Contemporaneous Emission Decrease	0
Net Emissions Increase	39.99
PSD Significant Level	40

Note: There were no increases or decreases other than those from the project.

Pollutant	Unit 7 Potential to Emit Prior To Modification (coal) Tons/Year	Unit 7 Potential to Emit After Modification (Nat Gas) Tons/Year	Unit 7 Increase (Decrease) Tons/Year	100 MMBtu/hr Natural gas Fired Auxiliary Boiler, tons/year
SO2	95711	11.2	-95700	0.26
NOx	11881	3807	-8074	15.9
CO	939	1199	260	16.2
VOC	47.5	102.6	55	0.00
PM	831	35	-795	0.82
PM10	28707	142	-28565	3.26
PM2.5	17342	142	-17200	3.26
Pb	6.43	0.0093	-6	2.15E-04
Be	1.03	0.0002	-1	5.15E-06
Hg	0.20	0.0049	0	1.12E-04
Sulfuric Acid Mist	11752	0.86	-11751	0.020
Flouride	119	0	-119	0
Single Largest HAP Coal (HCL)	950.46	0	-950	0
Single Largest HAP Nat. Gas (Hexane)	0.05	33.59	34	0.77
Total HAPs	1079.28	35.23	-1044	0.81
CO2e	2915581	2229446	-686135	51299

	Unit 7 Conversion ATPA, tons/year						
NSR Regulated Pollutant	Future Actual Emissions	Past Actual Emissions	Emissions That Could Have Been accomodated	ATPA for Unit 7	Natural gas Fired Auxiliary Boiler PTE	Hybrid ATPA for Modified Unit 7 & Aux. Boiler	PSD/EOR Significant Emission Threshold
SO2	9	1098	1.10	0	0.26	0.26	**40**
NOx*	3198	2657	712	0.00	15.9	15.9	**40**
CO**	1007	856	289	0.0	16.2	16.2	**100**
PM	30	1473	3.48	0	0.82	0.82	**25**
PM10	119	7668	13.9	0	3.26	3.26	**15**
PM2.5	119	7476	13.9	0	3.26	3.26	**10**
Pb	7.8E-03	1.5E-01	9.2E-04	0	2.15E-04	0.000215	**0.6**
Be	1.9E-04	2.5E-02	2.2E-05	0	5.15E-06	0.000005	**0.004**
Hg	4.1E-03	4.9E-03	4.8E-04	0	1.12E-04	0.000112	**0.1**
SAM	0.72	9937	0.084	0	0.020	0.020	**7**
Flouride	0.00	100.5	0	0	0	0	**3**
CO2e	1872735	3162523	218703	0	51299	51299	**75,000**

*** For NOx the baseline period is October 2012 through September 2014.**

**** For CO the baseline is based on CEMs data and the future actual is based on Manufacturer's guarantee.**

Coal	
11,400	Btu/lb
5.10	%S
11%	Ash
99.30%	ESP Cntrl Eff

Fuel Oil	
138,195	BTU/gal
0.30	%S

Natural gas	
1020	BTU/CF

ESP CE
98%

Current Case, Unit 7						Future Case, Unit 7			New Auxiliary Boiler
Coal				Fuel Oil		Natural Gas			Natural gas
Unit Rated Capacity, MMBtu per hour	Tons Coal per hour	Tons Coal/ year	MMBtu/ year	MMBtu/ hour	kgal/year	Unit Rated Capacity, MMBtu per hour	MMBTU per year	MMCF per year	Unit Rated Capacity, MMBtu per hour
4123	180.83	1,584,100	36,117,480	4123	257982	4346	38,070,960	37324	100.0

																	Global Warming Potentials			
																	1	25	298	
Fuel	Units	NOx	CO	VOC	SO2	CPM	PM Filt	PM10 Filt	PM10 Tot	PM2.5 Filt	PM2.5 Tot	SAM	Pb	Hg	Be	Fl	CO2	CH4	N2O	CO2e
Coal	lbs/Ton	*15*	*1.19*	0.06	*193.8*	10.944	*110*	*25.3*	36.244	*11.0*	21.9	14.8	8.11E-03	2.6E-04	1.3E-03	*0.15*	3357	0.39	0.06	3383
	lbs/MMBtu	0.658	*0.052*	0.00263	8.500	*0.48*	4.825	1.110	1.59	0.480	0.960	0.651	*5.07E-04*	*1.6E-05*	*8.1E-05*	0.007	*209.8*	*0.02425*	*0.00353*	211
No. 2 Fuel Oil	lbs/Kgal	*24*	*5*	*0.2*	*42.6*	*1.3*	*2*	*1*	*2.3*	*0.25*	*1.55*	*3.26*	1.24E-03	4.1E-04	4.1E-04	NA	22526	0.91	0.18	22603
	lbs/MMBtu	0.1737	0.0362	0.0014	0.308	0.009	0.014	0.007	0.017	0.002	0.011	0.024	*9.00E-06*	*3.0E-06*	*3.0E-06*	NA	163.00	6.61E-03	1.32E-03	164
Unit 7 Natural Gas	lbs/MMCF	204	64.26	*5.5*	*0.6*	*5.7*	*1.9*	*1.9*	*7.6*	*1.9*	*7.6*	0.046	*0.0005*	*2.6E-04*	*1.2E-05*	NA	119340	2.244	0.2244	119463
	Lbs/MMBtu	0.200	0.063	0.0054	0.00059	0.0056	0.0019	0.0019	0.0075	0.00186	0.0075	4.50E-05	4.90E-07	2.5E-07	1.2E-08	NA	*117.0*	*2.20E-03*	*2.20E-04*	117
Aux Boiler Natural gas	lbs/MMCF	37.128	37.638	*5.5*	*0.6*	*5.7*	*1.9*	*1.9*	*7.6*	*1.9*	*7.6*	0.046	*0.0005*	*2.6E-04*	*1.2E-05*	NA	119340	2.244	0.2244	119463
	Lbs/MMBtu	0.0364	0.0369	0.0054	0.00059	0.0056	0.0019	0.0019	0.0075	0.00186	0.0075	4.50E-05	4.90E-07	2.5E-07	1.2E-08	NA	*117.0*	*2.20E-03*	*2.20E-04*	117

SO2 Limit PM Limits/Boiler

5.3 lbs/ MMBtu 0.1 lbs/ MMBtu

Potential to Emit Assessment 830.7 tons/ year

	NOx	CO	VOC	SO2	PM Filt	PM10 Tot	PM2.5 Tot	SAM	Pb	Hg	Be	Fl	CO2	CH4	N2O	CO2e
Unlimited, Uncontrolled PTE with 100% coal	11880.8	939.1	47.5	153499	87126	28707	17342	11752	6.43	0.20	1.03	118.8	2658691	307.3	44.7	2679705
Unlimited, Uncontrolled PTE with 100%No. 2 Fuel Oil, tons/year	3095.8	645.0	25.8	5495	258	297	200	421	0.160	0.053	0.053		2905624	117.8	23.5	2915581
Limited, Uncontrolled PTE with 100% Coal, tons/year (Based on Permit restrictions for SO2 and PM*)	11880.8	939.1	47.5	95711	831	28707	17342	11752	6.425	0.203	1.026	118.8	2658691	307.3	44.7	2679705
limited PTE with either coal or oil , tons/year	11880.8	939.1	47.5	95711	831	28707	17342	11752	6.425	0.203	1.026	118.8	2905624	307.3	44.7	2915581
Unlimited, Uncontrolled PTE with 100% Natural Gas, tons/year	3807.1	1199.2	102.6	11.2	35.5	141.8	141.8	0.9	0.00933	0.00485	0.00022	0.00000	2227151	41.9	4.2	2229446
Project Increase (-Decrease) in PTE, tons/year	-8073.7	260.2	55.1	-95700.1	-795.2	-28565.2	-17199.9	-11751.4	-6.416	-0.198	-1.026	-118.8	-678472	-265.4	-40.5	-686135

*** SIP SO2 Limit = 5.3 lbs/MMBtu; SIP PM limit = 830.7 tons/year**

Actutal to Projected Actual (ATPA) Assessment

Baseline Actual Emissions

Baseline Period	Coal Usage	Fuel oil	Total MMBtu /year
	MMBtu/ year	MMBtu/ year	
October 2011 - September 2013 (For Everything Except NOx and CO)	30,537,269	39,671	30,576,940
Oct. 2012 through Sept. 2014 for NOx	28,889,481	57,742	28,947,223
Feb, 2011 through January 2013 for CO	29,882,761	47,543	29,930,304

Fuel	NOx	CO	VOC	SO2	PM Filt	PM10 Tot	PM2.5 Tot	SAM	Pb	Hg	Be	Fl	CO2	CH4	N2O	CO2e
Coal	2657	855.7	40.2	1097.6	1473.3	7667.8	7475.6	9936.5	1.55E-01	4.89E-03	2.47E-02	100.5	3,137,194	370.3	53.9	3,162,523
Oil			0.029		0.006	0.1895	0.1873	0.468	3.57E-06	1.19E-06	1.19E-06			1.31E-01	2.62E-02	
Totals	2657	855.7	40.2	1097.6	1473.3	7668.0	7475.8	9937.0	0.2	4.89E-03	2.47E-02	100.5	3,137,194	370.4	53.9	3,162,523

NOx, SO2, CO and CO2 based on CEM data

	MMBtu/ year Difference Between 95% availability level and Baseline
NOx	5364383
CO	4381302
All Other PSD Pollutants	3734666

Unit 7 Future Actual Maximum Usage 31,979,606 MMBtu /year @ 84% Capacity Factor

	NOx	CO	SO2	PM Filt	PM10 Tot	PM2.5 Tot	SAM	Pb	Hg	Be	Fl	CO2	CH4	N2O	CO2e
Unit 7 Future Actual Emissions, tons/year	3198	1007	9.41	29.78	119.14	119.14	0.72	7.8E-03	4.08E-03	1.88E-04	0.00	1870807	35.18	3.52	1872735
Unit 7 Baseline Emissions	2657	856	1098	1473	7668	7476	9937	1.55E-01	4.89E-03	2.47E-02	100.5	3137194	370	53.9	3162523
Unit 7 Future Actual Minus Baseline Actual	541	152	-1088	-1444	-7549	-7357	-9936	-1.47E-01	-8.11E-04	-2.45E-02	-100	-1266387	-335	-50	-1289788
Unit 7 Emissions that could have been accomodated	712	289.4	1.1	3.5	13.9	13.9	0.1	9.15E-04	4.76E-04	2.20E-05	0.00E+00	218478	4.1	0.4	218703
Unit 7 ATPA, tons/year	-171.0	-137.7	-1089	-1447.0	-7562.8	-7371	-9936	-0.1	0.0	0.0	-100.5	-1484865	-339.3	-50.8	-1508491
Unit 7 ATPA Adjusted, tons/year	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Auxilliary Boiler PTE, Natural gas, tons/year	15.9	16.2	0.26	0.82	3.26	3.26	0.02	0.00	0.00	0.00	NA	51246	0.96	0.10	51299
Unit 7 + Auxilliary Boiler Hybrid test ATPA, tons/year	**15.9**	**16.2**	**0.3**	**0.8**	**3.3**	**3.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**51246**	**1.0**	**0.1**	**51299**
PSD Significant Emission Increase Threshold, tons/year	**40**	**100**	**40**	**25**	**15**	**10**	**7**	**0.6**	**0.1**	**0.004**	**3**				**100000**
PSD Applicable?	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**				**No**

Unit 7 Rated Capacity	4123	MMBtu/hr Coal	4346	MMBtu/hr Natural gas
Unit 7 Potential Usage	1584100	tons of coal	37324	MMCF of Natural gas
Auxiliary Boiler Capacity			100	MMBtu/hr Natural gas
			859	MMCF/year of Natural Gas

Hazardous Air Pollutant	Emission Factors		Unit 7 PTE, Tons/year		Unit 7 Increase (decrease) in PTE, tons/year	Auxiliary Boiler PTE, tons/year
	Coal fired Boilers AP-42 Section 1.1, lbs/ton coal	Natural Gas Fired Boilers AP-42 Tables 1.4-3 and 1.4-5, lbs/MMCF	Coal	Natural gas		
Acetaldehyde	5.70E-04		0.45		-0.45	
Acetophone	1.50E-05		0.01		-0.01	
Acrolein	2.90E-04		0.23		-0.23	
Benzene	1.30E-03	2.10E-03	1.03	0.04	-0.99	9.02E-04
Benzyl Chloride	7.00E-04		0.55		-0.55	
Bis(2-ethylhexyl)phthalate (DEHP)	7.30E-05		0.06		-0.06	
Bromoform	3.90E-05		0.03		-0.03	
Carbon Disulfide	1.30E-04		0.10		-0.10	
2-Chloroacetophenone	7.00E-06		0.0055		-0.0055	
Chlorobenzene	2.20E-05		0.02		-0.02	
Chloroform	5.90E-05		0.05		-0.05	
Cumene	5.30E-06		0.0042		-0.0042	
Cyanide	2.50E-03		1.98		-1.98	
2,4-Dinitrotoluene	2.80E-07		0.00		0.00	
Dimethyl sulfate	4.80E-05		0.04		-0.04	
Ethyl benzene	9.40E-05		0.07		-0.07	
Ethyl chloride	4.20E-05		0.03		-0.03	
Ethylene dichloride	4.00E-05		0.03		-0.03	
Ethylene dibromide	1.20E-06		0.00		0.00	
Formaldehyde	**2.40E-04**	7.50E-02	0.19	1.40	1.21	3.22E-02
Hexane	6.70E-05	1.80E+00	0.05	33.59	33.54	7.73E-01
Isophorone	5.80E-04		0.46		-0.46	
Methyl bromide	1.60E-04		0.13		-0.13	
Methyl chloride	5.30E-04		0.42		-0.42	
Methyl ethyl ketone	3.90E-04		0.31		-0.31	
Methyl hydrazine	1.70E-04		0.13		-0.13	
Methyl methacrylate	2.00E-05		0.02		-0.02	
Methyl tert butyl ether	3.50E-05		0.03		-0.03	
Methylene chloride	2.90E-04		0.23		-0.23	
Phenol	1.60E-05		0.01		-0.01	
Propionaldehyde	3.80E-04		0.30		-0.30	
Tetrachloroethylene	4.30E-05		0.03		-0.03	
Toluene	2.40E-04	3.40E-03	0.19	0.06345	-0.13	1.46E-03
1,1,1-Trichloroethane	2.00E-05		0.016		-0.016	
Styrene	2.50E-05		0.020		-0.020	
Xylenes	3.70E-05		0.029		-0.029	
Vinyl acetate	7.60E-06		0.006		-0.006	

Hazardous Air Pollutant	Emission Factors		Unit 7 PTE, Tons/year		Unit 7 Increase (decrease) in PTE, tons/year	Auxiliary Boiler PTE, tons/year
	Coal fired Boilers AP-42 Section 1.1, lbs/ton coal	Natural Gas Fired Boilers AP-42 Tables 1.4-3 and 1.4-5, lbs/MMCF	Coal	Natural gas		
1,3-Butadiene		3.91E-05		0.00073	0.000730	1.68E-05
Naphthalene	1.30E-05	6.10E-04	0.01030	0.01138	0.001087	2.62E-04
Acenaphthylene	2.50E-07	1.80E-06	0.00020	0.00003	-0.000164	7.73E-07
Acenaphthene	5.10E-07	1.80E-06	0.00040	0.00003	-0.000370	7.73E-07
Fluorene	9.10E-07	2.80E-06	0.00072	0.00005	-0.000669	1.20E-06
Phenanthrene	2.70E-06	1.70E-05	0.00214	0.00032	-0.001821	7.30E-06
Anthracene	2.10E-07	2.40E-06	0.00017	0.00004	-0.000122	1.03E-06
Fluoranthene	7.10E-07	3.00E-06	0.00056	0.00006	-0.000506	1.29E-06
Pyrene	3.30E-07	5.00E-06	0.00026	0.00009	-0.000168	2.15E-06
Benz(a)anthracene	8.00E-08	1.80E-06	0.00006	0.00003	-0.000030	7.73E-07
5-methyl chrysene	2.20E-08		0.00002		-0.000017	
Chrysene	1.00E-07	1.80E-06	0.00008	0.00003	-0.000046	7.73E-07
Benzo(b)fluoranthrene	1.10E-07	1.80E-06	0.00009	0.00003	-0.000054	7.73E-07
Benzo(k)fluoranthrene		1.80E-06		0.00003	0.000034	7.73E-07
Benzo(a)pyrene	3.80E-08	1.20E-06	0.00003	0.00002	-0.000008	5.15E-07
Indeno(1,2,3-cd)pyrene	6.10E-08	1.80E-06	0.000048	0.00003	-0.000015	7.73E-07
Dibenz(a,h)anthracene		1.20E-06	0.000000	0.00002	0.000022	5.15E-07
Benzo(g,h,l)perylene	2.70E-08	1.20E-06	0.000021	0.00002	0.000001	5.15E-07
2 Methylnapthalene		2.50E-05		0.00047	0.000467	1.07E-05
3 methylcloranthene		1.60E-06		0.00003	0.000030	6.87E-07
7,12-Dimethylbenz(a)anthracene		1.60E-05		0.00030	0.000299	6.87E-06
Dichlorobenzene		1.20E-03		0.02239	0.022	5.15E-04
Antimony	1.80E-05		0.014		-0.014	
Arsenic	4.10E-04	2.00E-04	0.32	0.00373	-0.32	8.59E-05
Beryllium	2.10E-05	1.20E-05	0.017	0.00022	-0.016	5.15E-06
Cadmium	5.10E-05	1.10E-03	0.040	0.02053	-0.020	4.72E-04
Chromium	2.60E-04	1.40E-03	0.206	0.02613	-0.180	6.01E-04
Cobalt	1.00E-04	8.40E-05	0.079	0.00157	-0.078	3.61E-05
Lead	4.20E-04		0.33		-0.33	
Manganese	4.90E-04	3.80E-04	0.39	0.00709	-0.38	1.63E-04
Mercury	8.30E-05	2.60E-04	0.066	0.00485	-0.061	1.12E-04
Nickel	2.80E-04	2.10E-03	0.22	0.03919	-0.18	9.02E-04
Selenium	1.30E-03	2.40E-05	1.03	0.00045	-1.03	1.03E-05
HCL	1.2		950.46		-950.46	
HF	0.15		118.81		-118.81	
Total PCDD/PCDF	2.44E-07		0.000193		-0.000193	
Total HAPs		**1.89E+00**	**1079.28**	**35.23**	**-1044.04**	**0.81**

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: Indianapolis Power & Light Company - Harding Street Station
Address City IN Zip: 3700 & 4190 S. Harding Street
Permit Number: 097-35518-00033
Reviewer: Josiah Balogun
Date: 10-Mar-2015

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
100.0	1020	858.8

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	37.128 **see below	5.5	37.638
Potential Emission in tons/yr	0.82	3.3	3.3	0.3	15.9	2.36	16.2

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

HAPS Calculations

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	9.018E-04	5.153E-04	3.221E-02	7.729E-01	1.460E-03	**8.080E-01**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	2.147E-04	4.724E-04	6.012E-04	1.632E-04	9.018E-04	**2.353E-03**

Total HAPs	**8.104E-01**
Worst HAP	**7.729E-01**

Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Greenhouse Gas Calculations

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	51,529	1.0	0.9
Summed Potential Emissions in tons/yr	51,531		
CO2e Total in tons/yr	51,836		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) +

Appendix A: Emission Calculations
Natural Gas Combustion Only
MMBTU/HR >100
Utility Boiler

Company Name: Indianapolis Power & Light Company - Harding Street Station
Address City IN Zip: 3700 & 4190 S. Harding Street
Permit Number: 097-35518-00033
Reviewer: Josiah Balogun
Date: 10-Mar-2015

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
4346.0	1020	37324.5

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	204.0 **see below	5.5	64.3
Potential Emission in tons/yr	35.5	141.8	141.8	11.2	3807.1	102.6	1199.0

*PM emission factor is filterable PM only. PM10 emission factor is condensable and filterable PM10 combined.
PM2.5 emission factor is condensable and filterable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 280 (pre-NSPS) or 190 (post-NSPS), Low NOx Burner = 140, Flue gas recirculation = 100 (See Table 1.4-1)

Methodology

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

See page 2 for HAPs emissions calculations.

Appendix A: Emission Calculations
Natural Gas Combustion Only
MMBTU/HR >100
HAPs Emissions

Company Name: Indianapolis Power & Light Company - Harding Street Station
Address City IN Zip: 3700 & 4190 S. Harding Street
Permit Number: 097-33140-00033
Reviewer: Josiah Balogun
Date: 10-Mar-2015

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	3.92E-02	2.24E-02	1.40E+00	3.36E+01	6.35E-02	Total 3.51E+01

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	9.33E-03	2.05E-02	2.61E-02	7.09E-03	3.92E-02	Total 1.02E-01

Total HAPs	**3.522E+01**
Worst HAP	**3.359E+01**

Methodology is the same as page 1.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.
See Page 3 for Greenhouse Gas calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MMBTU/HR >100
Greenhouse Gas Emissions

Company Name: Indianapolis Power & Light Company - Harding Street Station
Address City IN Zip: 3700 & 4190 S. Harding Street
Permit Number: 097-33140-00033
Reviewer: Josiah Balogun
Date: 10-Mar-2015

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	2,239,468	42.9	41.1
Summed Potential Emissions in tons/yr	2,239,552		
CO2e Total in tons/yr	2,252,776		

Methodology

The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.

Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

IPL Harding Street Unit 70 Monthly Air Emissions

Oil 0.138195

Year	Month	SO2 Tons	NOX Tons	CO2 Tons	Heat Input MMBtummbtu	Oil Gallons Used	MMBtu Input Oil	MMBtu input Coal
2010	January	141.4	104.4	284,437.5	2,772,290	3796	525	2,771,765
2010	February	94.3	87.7	182,213.5	1,775,964	96452	13,329	1,762,635
2010	March	155.4	74.0	189,901.9	1,850,901	74821	10,340	1,840,561
2010	April	89.6	97.8	253,751.2	2,473,212	9021	1,247	2,471,965
2010	May	87.6	101.2	252,812.0	2,464,063	36705	5,072	2,458,991
2010	June	144.1	108.1	241,517.6	2,353,987	16133	2,229	2,351,758
2010	July	154.1	75.6	227,917.6	2,221,418	46571	6,436	2,214,982
2010	August	145.1	116.9	240,995.7	2,348,889	53251	7,359	2,341,530
2010	September	92.4	103.1	189,085.4	1,842,931	0	0	1,842,931
2010	October	0.0	0.0	0.0	0	0	0	0
2010	November	0.0	0.0	0.0	0	0	0	0
2010	December	608.4	154.7	100,760.6	982,080	121793	16,831	965,249
2011	January	925.4	192.6	134,680.2	1,312,687	54558	7,540	1,305,147
2011	February	247.4	116.9	277,368.3	2,703,390	17746	2,452	2,700,938
2011	March	162.4	96.0	289,166.6	2,818,375	0	0	2,818,375
2011	April	67.8	76.5	219,183.9	2,136,304	67891	9,382	2,126,922
2011	May	322.6	87.6	312,031.2	3,041,238	0	0	3,041,238
2011	June	75.9	75.6	185,912.5	1,812,012	78302	10,821	1,801,191
2011	July	273.7	121.5	266,834.1	2,600,717	25589	3,536	2,597,181
2011	August	40.2	41.4	117,441.7	1,144,654	31603	4,367	1,140,287
2011	September	50.3	77.6	261,571.5	2,549,433	52192	7,213	2,542,220
2011	October	134.2	96.2	272,201.6	2,653,036	9076	1,254	2,651,782
2011	November	75.3	95.1	277,978.4	2,709,337	5539	765	2,708,572
2011	December	44.5	100.4	295,087.0	2,876,092	36284	5,014	2,871,078
2012	January	64.0	135.4	289,493.7	2,821,574	41266	5,703	2,815,871
2012	February	52.3	287.2	253,603.9	2,471,766	34269	4,736	2,467,030
2012	March	57.7	94.0	306,846.1	2,990,712	11124	1,537	2,989,175
2012	April	20.7	60.0	187,685.6	1,829,299	0	0	1,829,299
2012	May	26.2	63.5	104,688.4	1,020,358	44740	6,183	1,014,175
2012	June	78.5	95.5	306,827.8	2,990,536	3667	507	2,990,029
2012	July	63.1	147.6	289,970.3	2,826,222	12963	1,791	2,824,431
2012	August	65.9	57.4	165,121.2	1,609,365	52441	7,247	1,602,118
2012	September	71.1	121.5	290,036.6	2,826,854	833	115	2,826,739
2012	October	67.5	116.8	215,325.2	2,098,678	21696	2,998	2,095,680
2012	November	80.2	168.2	242,348.6	2,362,076	45568	6,297	2,355,779
2012	December	93.9	147.4	296,891.7	2,893,680	4880	674	2,893,006
2013	January	120.9	105.7	300,165.1	2,925,600	8706	1,203	2,924,397
2013	February	80.4	272.7	221,472.1	2,158,592	59725	8,254	2,150,338
2013	March	166.7	134.0	298,289.4	2,907,303	52695	7,282	2,900,021
2013	April	134.3	447.9	278,738.8	2,716,754	45181	6,244	2,710,510
2013	May	103.4	305.3	230,416.5	2,245,772	32725	4,522	2,241,250
2013	June	183.8	246.9	316,999.4	3,089,663	675	93	3,089,570
2013	July	114.6	129.7	275,088.8	2,681,189	30122	4,163	2,677,026
2013	August	126.1	96.3	278,160.2	2,711,112	14607	2,019	2,709,093
2013	September	169.9	144.2	280,950.7	2,738,310	5348	739	2,737,571
2013	October	205.8	144.6	223,567.8	2,179,022	34546	4,774	2,174,248
2013	November	305.1	212.7	246,714.0	2,404,632	44659	6,172	2,398,460
2013	December	335.4	370.1	249,729.7	2,434,012	50656	7,000	2,427,012
2014	January	394.7	533.8	282,059.1	2,749,101	76226	10,534	2,738,567
2014	February	297.6	492.4	260,277.5	2,536,820	39403	5,445	2,531,375
2014	March	119.3	169.6	69,883.7	681,133	2537	351	680,782
2014	April	838.9	233.0	127,799.2	1,245,602	82749	11,435	1,234,167
2014	May	243.4	224.2	217,892.0	2,123,714	81064	11,203	2,112,511
2014	June	264.0	144.8	245,067.7	2,388,572	29571	4,087	2,384,485
2014	July	215.5	158.4	259,756.3	2,531,729	31405	4,340	2,527,389
2014	August	232.9	135.9	272,967.0	2,660,488	13546	1,872	2,658,616
2014	September	162.0	149.4	249,410.3	2,430,892	27373	3,783	2,427,109
2014	October		146.4		3,058,107			3,058,107
2014	November		135.8		2,274,985			2,274,985
2014	December		169.8		2,952,397			2,952,397

MMBtu/gal

Annual values based on 12-month rolling						Annual based on 24-month rolling							
Tons SO2 rolling 12-month	Tons Nox Rolling 12-month	Tons CO2 Rolling 12-month	MMBtuTotal Rolling 12-month	MMBtu Oil Rolling 12-month	MMBtu Coal Rolling 12-month	Tons SO2 rolling 24-month	Tons Nox Rolling 24-month	Tons CO2 Rolling 24-month	MMBtuTotal Rolling 24-month	MMBtu Oil Rolling 24-month	MMBtu Coal Rolling 24-month		NOX, Lbs/MMBTU
													0.0753168
													0.09876326
													0.07996106
													0.07908744
													0.08214076
													0.09184418
													0.06806463
													0.09953642
													0.11188699
1712.4	1023.5	2163393.0	21085735.0	63368.3	21022366.7								0.31504562
2496.4	1111.7	2013635.7	19626132.0	70383.4	19555748.6								0.29344391
2649.5	1140.9	2108790.5	20553558.0	59506.6	20494051.4								0.08648401
2656.5	1162.9	2208055.2	21521032.0	49166.7	21471865.3								0.06812436
2634.7	1141.6	2173487.9	21184124.0	57302.3	21126821.7								0.07161902
2869.7	1128.0	2232707.1	21761299.0	52229.8	21709069.2								0.05760812
2801.5	1095.5	2177102.0	21219324.0	60821.3	21158502.7								0.08344316
2921.1	1141.4	2216018.5	21598623.0	57921.7	21540701.3								0.09343577
2816.2	1065.9	2092464.5	20394388.0	54930.0	20339458.0								0.07233627
2774.1	1040.4	2164950.6	21100890.0	62142.7	21038747.3								0.06087628
2908.3	1136.6	2437152.2	23753926.0	63397.0	23690529.0								0.07252069
2983.6	1231.7	2715130.6	26463263.0	64162.4	26399100.6								0.07020168
2419.7	1177.4	2909457.0	28357275.0	52345.5	28304929.5	2,066	1,100	2,536,425	24,721,505	57,857	24,663,648		0.06981696
1558.3	1120.2	3064270.5	29866162.0	50508.6	29815653.4	2,027	1,116	2,538,953	24,746,147	60,446	24,685,701		0.0959748
1363.2	1290.5	3040506.1	29634538.0	52792.0	29581746.0	2,006	1,216	2,574,648	25,094,048	56,149	25,037,899		0.23238446
1258.5	1288.5	3058185.6	29806875.0	54329.3	29752545.7	1,958	1,226	2,633,120	25,663,954	51,748	25,612,205		0.06286129
1211.4	1272.0	3026687.3	29499870.0	44947.1	29454922.9	1,923	1,207	2,600,088	25,341,997	51,125	25,290,872		0.0655989
915.0	1247.9	2819344.5	27478990.0	51129.9	27427860.1	1,892	1,188	2,526,026	24,620,145	51,680	24,568,465		0.12446612
917.6	1267.8	2940259.8	28657514.0	40815.8	28616698.2	1,860	1,182	2,558,681	24,938,419	50,819	24,887,600		0.06386815
707.0	1293.9	2963396.0	28883019.0	39070.9	28843948.1	1,814	1,218	2,589,707	25,240,821	48,496	25,192,325		0.10445039
732.7	1309.9	3011075.5	29347730.0	41950.6	29305779.4	1,774	1,188	2,551,770	24,871,059	48,440	24,822,619		0.07133248
753.5	1353.8	3039540.6	29625151.0	34853.1	29590297.9	1,764	1,197	2,602,246	25,363,021	48,498	25,314,523		0.08596128
686.8	1374.4	2982664.2	29070793.0	36597.1	29034195.9	1,798	1,256	2,709,908	26,412,360	49,997	26,362,362		0.11130817
691.7	1447.5	2947034.4	28723532.0	42128.9	28681403.1	1,838	1,340	2,831,083	27,593,398	53,146	27,540,252		0.14241709
741.1	1494.5	2948839.1	28741120.0	37789.0	28703331.0	1,580	1,336	2,929,148	28,549,198	45,067	28,504,130		0.10187719
798.0	1464.8	2959510.5	28845146.0	33289.4	28811856.6	1,178	1,293	3,011,891	29,355,654	41,899	29,313,755		0.07225868
826.1	1450.3	2927378.7	28531972.0	36807.3	28495164.7	1,095	1,370	2,983,942	29,083,255	44,800	29,038,455		0.2526647
935.1	1490.3	2918822.0	28448563.0	42552.2	28406010.8	1,097	1,389	2,988,504	29,127,719	48,441	29,079,278		0.09218165
1048.7	1878.2	3009875.2	29336018.0	48796.0	29287222.0	1,130	1,575	3,018,281	29,417,944	46,872	29,371,072		0.32973173
1125.9	2120.0	3135603.3	30561432.0	47135.6	30514296.4	1,020	1,684	2,977,474	29,020,211	49,133	28,971,078		0.27188869
1231.2	2271.4	3145774.9	30660559.0	46722.1	30613836.9	1,074	1,770	3,043,017	29,659,037	43,769	29,615,268		0.15982326
1282.7	2253.5	3130893.4	30515526.0	49093.4	30466432.6	995	1,774	3,047,145	29,699,273	44,082	29,655,190		0.09674812
1342.9	2292.4	3243932.4	31617273.0	43864.9	31573408.1	1,038	1,801	3,127,504	30,482,502	42,908	30,439,594		0.07104096
1441.7	2315.1	3234846.5	31528729.0	44488.8	31484240.2	1,098	1,834	3,137,194	30,576,940	39,671	30,537,269		0.10532043
1580.0	2342.9	3243089.1	31609073.0	46264.6	31562808.4	1,133	1,859	3,112,877	30,339,933	41,431	30,298,502		0.13272009
1804.9	2387.4	3247454.5	31651629.0	46139.0	31605490.0	1,248	1,917	3,097,244	30,187,581	44,134	30,143,447		0.17690857
2046.4	2610.1	3200292.5	31191961.0	52465.0	31139496.0	1,394	2,052	3,074,566	29,966,541	45,127	29,921,413		0.30410696
2320.2	3038.2	3182186.5	31015462.0	61796.0	30953666.0	1,559	2,252	3,070,849	29,930,304	47,543	29,882,761		0.38834514
2537.4	3257.9	3220991.9	31393690.0	58987.6	31334702.4	1,682	2,354	3,074,185	29,962,831	47,897	29,914,934		0.38820255
2490.0	3293.5	2992586.2	29167520.0	52056.0	29115464.0	1,713	2,392	2,955,704	28,808,042	47,304	28,760,737		0.49799378
3194.6	3078.6	2841646.6	27696368.0	57247.7	27639120.3	2,122	2,478	2,925,761	28,516,193	53,022	28,463,171		0.37411629
3334.6	2997.5	2829122.1	27574310.0	63927.9	27510382.1	2,230	2,559	2,982,363	29,067,871	55,532	29,012,339		0.21113954
3414.8	2895.4	2757190.4	26873219.0	67921.2	26805297.8	2,323	2,583	2,951,483	28,766,889	57,322	28,709,567		0.12124399
3515.7	2924.1	2741857.9	26723759.0	68098.5	26655660.5	2,399	2,589	2,936,376	28,619,643	58,596	28,561,047		0.12513188
3622.5	2963.7	2736664.7	26673135.0	67951.9	26605183.1	2,483	2,628	2,990,299	29,145,204	55,908	29,089,296		0.10216171
3614.6	2968.9	2705124.3	26365717.0	70995.6	26294721.4	2,528	2,642	2,969,985	28,947,223	57,742	28,889,481		0.12291784
	2970.7		27244802.0				2,657		29,426,938		29,370,694		
	2893.8		27115155.0				2,641		29,383,392		29,330,298	Average	0.1429219
	2693.5		27633540.0				2,652		29,412,751		29,359,993	Max	0.49799378
												Min	0.05760812

August 5, 2015

Ms. Jennifer Hatfield
Indianapolis Power & Light Company - Harding Street Station
3700 S Harding Street
Indianapolis, IN 46217

Re: Public Notice
Indianapolis Power & Light Company - Harding Street Station
Permit Level: Title V - Significant Source Modification & Title V - Significant Permit Modification
Permit Number: 097 - 35518 - 00033 & 097 - 35534 - 00033

Dear Ms. Hatfield:

Enclosed is a copy of your draft Title V - Significant Source Modification & Title V - Significant Permit Modification, Technical Support Document, emission calculations, and the Public Notice which will be printed in your local newspaper.

The Office of Air Quality (OAQ) has prepared two versions of the Public Notice Document. The abbreviated version will be published in the newspaper, and the more detailed version will be made available on the IDEM's website and provided to interested parties. Both versions are included for your reference. The OAQ has requested that the Indianapolis Star in Indianapolis, IN publish the abbreviated version of the public notice no later than August 8, 2015. You will not be responsible for collecting any comments, nor are you responsible for having the notice published in the newspaper.

OAQ has submitted the draft permit package to the Indianapolis Central Library Branch, 40 East St. Clair Street in Indianapolis IN. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the enclosed documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Josiah Balogun, Indiana Department of Environmental Management, Office of Air Quality, 100 N. Senate Avenue, Indianapolis, Indiana, 46204 or call (800) 451-6027, and ask for extension 4-5257 or dial (317) 234-5257.

Sincerely,

Len Pogost

Len Pogost
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover lette-2014. Dot4/10/14

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

100 N. Senate Avenue • Indianapolis, IN 46204

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

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

ATTENTION: PUBLIC NOTICES, LEGAL ADVERTISING

August 5, 2015

Indianapolis Star
Attn: Classifieds
130 S. Meridian St.
Indianapolis, Indiana 46225

Enclosed, please find one Indiana Department of Environmental Management Notice of Public Comment for Indianapolis Power & Light Company - Harding Street Station, Marion County, Indiana.

Since our agency must comply with requirements which call for a Notice of Public Comment, we request that you print this notice one time, no later than August 8, 2015.

Please send a notarized form, clippings showing the date of publication, and the billing to the Indiana Department of Environmental Management, Accounting, Room N1345, 100 North Senate Avenue, Indianapolis, Indiana, 46204.

To ensure proper payment, please reference account # 100174737.

We are required by the Auditor's Office to request that you place the Federal ID Number on all claims. If you have any conflicts, questions, or problems with the publishing of this notice or if you do not receive complete public notice information for this notice, please call Len Pogost at 800-451-6027 and ask for extension 3-2803 or dial 317-233-2803.

Sincerely,

Len Pogost

Len Pogost
Permit Branch
Office of Air Quality

Permit Level: Title V - Significant Source Modification & Title V - Significant Permit Modification
Permit Number: 097 - 35518 - 00033 & 097 - 35534 - 00033

Enclosure
PN Newspaper.dot 6/13/2013

August 5, 2015

To: Indianapolis Central Library Branch 40 East St. Clair Street Indianapolis IN

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

Subject: **Important Information to Display Regarding a Public Notice for an Air Permit**

Applicant Name: Indianapolis Power & Light Company - Harding Street Station
Permit Number: 097 - 35518 - 00033 & 097 - 35534 - 00033

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Request to publish the Notice of 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. **Please make this information readily available until you receive a copy of the final package.**

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. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library.dot 6/13/2013

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

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

Notice of Public Comment

August 5, 2015
Indianapolis Power & Light Company - Harding Street Station
097 - 35518 - 00033 & 097 - 35534 - 00033

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has been placed in the Legal Advertising section of your local newspaper. The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana's Air Permitting Program.

Please Note: *If you feel you have received this Notice 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. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
PN AAA Cover.dot 6/13/13

Mail Code 61-53

IDEM Staff	LPOGOST 8/5/2015 Indianapolis Power & Light Company - Harding St 097 - 35518 & 35534 - 00033 draft			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		Jennifer Hatfield Indianapolis Power & Light Company - Harding Stree 3700 S Harding Street Indianapolis IN 46217 (Source CAATS)									
2		Marion County Health Department 3838 N, Rural St Indianapolis IN 46205-2930 *(Health Department)*									
3		Indianapolis Central Library Branch 40 East St. Clair Street Indianapolis IN 46204 *(Library)*									
4		Indianapolis City Council 200 East Washington Street, Room E Indianapolis IN 46204 *(Local Official)*									
5		Marion County Commissioners 200 E. Washington St. City County Bldg., Suite 801 Indianapolis IN 46204 *(Local Official)*									
6		Tom Rarick Environmental Resources Management (ERM) 8425 Woodfield Crossing Blvd, Suite 560-W Indianapolis IN 46240 *(Consultant)*									
7		Matt Mosier Office of Sustainability City-County Bldg/200 E Washington St. Rm# 2460 Indianapolis IN 46204 *(Local Official)*									
8		Justin Barrett IPL One Monument Circle Indianapolis IN 46204 *(Source – addl contact)*									
9		Johan & Susan Van Den Heuvel 4409 Blue Creek Drive Carmel IN 46033 *(Affected Party)*									
10		Indiana Members Credit Union 5103 Madison Avenue Indianapolis IN 46227 *(Affected Party)*									
11											
12											
13											
14											
15											

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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