INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

TO: Interested Parties / Applicant

DATE: June 21, 2013

RE: Laketon Refining Corporation / 169-33207-00006

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

Notice of Decision – Approval

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to 326 IAC 2, this approval was effective immediately upon submittal of the application.

If you wish to challenge this decision, IC 4-21.5-3-7 requires that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar days from the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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

Enclosures
FNPER-AM.dot 6/13/2013

Norman Burkett
Laketon Refining Corporation
2784 W Lukens Lake Rd
Laketon, IN, 46943

Re: 169-33207-00006
First Administrative Amendment to
M169-29989-00006

Dear Norman Burkett:

Laketon Refining Corporation was issued a Minor Source Operating Permit (MSOP) Renewal No. M169-29989-00006 on June 24, 2011 for a stationary asphalt liquid binder manufacturing source located at 2784 W Lukens Lake Rd, Laketon, IN 46943. On May 13, 2013, the Office of Air Quality (OAQ) received an application from the source requesting to include in the permit four (4) additional small welded steel fixed-roof storage tanks (ST-062, ST-063, ST-064, and ST-065) used to store petroleum asphalt of various grades and to remove two (2) storage tanks (ST-055 and ST-056) from the permit, which were never constructed.

1. Pursuant to 326 IAC 2-6.1-6(d)(2)(A), this change to the permit is considered an administrative amendment because the permit is amended to change the descriptive information concerning the source of emissions unit, where the revision will not trigger a new application requirement.

2. Pursuant to 326 IAC 2-6.1-6(d)(11), this change to the permit is considered an administrative amendment because the permit is amended to add an emissions unit, subject to 326 IAC 2-1.1-3 (Exemptions), at the request of the applicant.

   The following are the emissions units:

   Four (4) asphalt vertical fixed roof storage tanks, known as ST-062, ST-063, ST-064, and ST-065, each constructed in 2011, capacity: 49,405 gallons each.

   The uncontrolled/unlimited potential to emit of the entire source after the removal of the two (2) storage tanks (ST-055 and ST-056) and addition of the four (4) new storage tanks (ST-062, ST-063, ST-0064, and ST-065) will continue to be within the threshold levels specified in 326 IAC 2-6.1 (MSOP). See Appendix A for the calculations.

   The PTE of the emission unit is as follows:

Process/ Emission Unit	PTE of Proposed Modification (tons/year)									
	PM	PM10	PM2.5	SO_2	NOx	VOC	CO	GHGs as CO_2e	Total HAPs	Worst Single HAP
ST-062, ST-063, ST-064, ST-064	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total PTE of Proposed Modification	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

   (a) The uncontrolled/unlimited potential to emit of the entire source after the addition of this emission unit will continue to be within the threshold levels specified in 326 IAC 2-5.1 (MSOP). (See Appendix A for the calculations).

(b) The incorporation of the modification will not cause the source's potential to emit to be greater than the threshold levels specified in 326 IAC 2-2 (PSD), 326 IAC 2-3 (Emission Offset), or 326 IAC 2-7 (Part 70).

(c) No new state rules are applicable to this source due to the addition of the emission unit.

(d) There are no New Source Performance Standards (NSPS) (326 IAC 12 and 40 CFR Part 60) or National Emission standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 20 and 40 CFR Part 61, 63) included in this administrative amendment.

PTE of the Entire Source After Issuance of the MSOP Administrative Amendment

The table below summarizes the potential to emit of the entire source after issuance of this revision, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this MSOP permit revision, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of MSOP Adminstrative Amendment (tons/year)									
	PM	PM10*	PM2.5*	SO_2	NOx	VOC	CO	GHGs as CO_2e**	Total HAPs	Worst Single HAP
***Natural Gas	0.4	1.5	1.5	0.1	19.1	1.1	16.1	23,109	3.60E-01	3.45E-01 Hexane
***No. 1 Fuel, No. 2 Fuel	2.7	2.7	2.7	97.1	27.3	0.5	6.8	23,109	9.40E-03	2.87E-03 Selenium
***Biofuel	2.7	2.7	2.7	97.1	30.1	0.5	6.8	23,109	9.40E-03	2.87E-03 Selenium
WORST CASE FUEL	2.7	2.7	2.7	97.1	30.1	1.1	16.1	23,109	3.60E-01	3.45E-01 Hexane
Combustion Sources Natural Gas Only Heater THE-930, Heater HO-2	0.1	0.3	0.3	0.0	4.5	0.2	3.8	0.0	8.60E-02	8.16E-02 Hexane
Loading Racks LR-1, LR-2, LR-3	0.0	0.0	0.0	0.0	0.0	2.18E-01	0.0	0.0	0.0	0.0
VOC Emissions from Tanks	0.0	0.0	0.0	0.0	0.0	3.800E-02	0.0	0.0	0.0	0.0
VOC Emissions from Misc. Sources	0.0	0.0	0.0	0.0	0.0	5.52E-01	0.0	0.0	0.0	0.0
Total Uncontrolled Emissions	**2.8**	**3.0**	**3.0**	**97.1**	**34.6**	**2.11**	**19.9**	**23,109**	**0.446**	0.0 Hexane
Title V Major Source Thresholds**	NA	100	100	100	100	100	100	100,000	25	10
PSD Major Source Thresholds**	250	250	250	250	250	250	250	100,000	NA	NA

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of MSOP Adminstrative Amendment (tons/year)									
	PM	PM10*	PM2.5*	SO_2	NOx	VOC	CO	GHGs as CO_2e**	Total HAPs	Worst Single HAP

negl. = negligible
*Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), not particulate matter (PM), is considered as a "regulated air pollutant".
**The 100,000 CO_2e threshold represents the Title V and PSD subject to regulation thresholds for GHGs in order to determine whether a source's emissions are a regulated NSR pollutant under Title V and PSD.
(a) VOC emissions are limited to less than 25 tons/year to render 326 IAC 8-1-6 not applicable to EU-05.

Pursuant to the provisions of 326 IAC 2-6.1-6, the permit is hereby amended as follows with the deleted language as ~~strikeouts~~ and new language **bolded**.

…

A.2 Emission Units and Pollution Control Equipment Summary

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

…

~~(m) Two (2) asphalt vertical fixed roof storage tanks, known as ST-055 and ST-056, approved for construction in 2011, capacity: 635,460 gallons each. Note: These two units replace the previous tank ST-055, constructed in 1968, that had a capacity of 1,270,980 gallons, which was removed from service in 2011.~~

(n) Four (4) asphalt vertical fixed roof storage tanks, known as ST-062, ST-063, ST-064, and ST-065, each approved for construction in 2013, capacity: 49,405 gallons each.

…

Below is a table summary of the tanks permitted at this source.

Tank I.D.	Material Stored	Construction Date	Capacity (gallons)	Type of Tank (e.g. vertical fixed roof)
ST-009	Asphalt	1895	1,470,000	vertical fixed roof
ST-010	Asphalt	1895	1,470,000	vertical fixed roof
ST-007	Oils, Reuse solvent	1956	289,800	internal floating roof
ST-029	Asphalt	1956	428,400	vertical fixed roof
~~ST-055~~	~~Asphalt~~	~~2011~~	~~635,460~~	~~vertical fixed roof~~
~~ST-056~~	~~Asphalt~~	~~2011~~	~~635,460~~	~~vertical fixed roof~~
ST-062	**Asphalt**	**2013**	**49,405**	**vertical fixed roof**
ST-063	**Asphalt**	**2013**	**49,405**	**vertical fixed roof**
ST-064	**Asphalt**	**2013**	**49,405**	**vertical fixed roof**
ST-065	**Asphalt**	**2013**	**49,405**	**vertical fixed roof**
ST-021	Oils, kerosene	1975	8,820	vertical fixed roof
ST-060	Asphalt	1985	2,341,920	vertical fixed roof
ST-061	Asphalt	1985	5,019,042	vertical fixed roof
ST-090	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-091	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-092	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-093	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-094	Oils, asphalt products	1994	30,000	vertical fixed roof
ST-095	Oils, asphalt products	1994	30,000	vertical fixed roof
ST-096	Anti-stripping Additive	1999	13,000	vertical fixed roof

…

Additional Changes

(1) Pursuant to 326 IAC 2-7-1(39), starting July 1, 2011, greenhouse gases (GHGs) emissions are subject to regulation at a source with a potential to emit (PTE) 100,000 tons per year or more of CO2 equivalent emissions (CO2e). Therefore, CO2e emissions have been calculated for this source. Based on the calculations, the unlimited PTE GHGs from the entire source is less than 100,000 tons of CO2e per year (see Appendix A for the calculations). This did not require any changes to the permit.

(2) On January 30, 2013, amendments to 326 IAC 8-3 (Organic Solvent Degreasing Operations) were published, effective March 1, 2013. 326 IAC 8-3-2 was revised and 326 IAC 8-3-5 was repealed. The Permittee is now subject to 326 IAC 8-3-8 on and after January 1, 2015.

(3) On March 21, 2011, the U.S. EPA published the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, with an effective date of May 21, 2011. The requirements of 40 CFR 63, Subpart JJJJJJ, are not included in the permit for the natural gas-fired steam boilers identified as SB-903 and SB-904, because each is a gas-fired boiler as defined in 40 CFR 63.11237.

> Pursuant to 40 CFR 63.11237, "Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year".

SB-903 and SB-904 are natural gas-fired boilers capable of using No. 1 or No. 2 fuel oils and biofule as backup fuels. Section III *Summary of This Final Rule*'s, Subpart A, published in the Federal Register, (Volume 76, Number 54, Page 15559) on Monday, March 21, 2011, states that "This rule applies to you if you own or operate a boiler combusting natural gas, located at an area source, which switches to combusting solid fossil fuels, biomass, or liquid fuel after June 4, 2010. Since these facilities have not combusted liquid fuels after June 4, 2010, they meet the exemption outlined in 40 CFR 63.11195(e) for gas-fired boilers.

At any time these facilities no longer meet the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the source shall comply with the applicable requirements of 40 CFR 63, Subpart JJJJJJ.

The permit has been revised as follows. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text:

…

A.2 Emission Units and Pollution Control Equipment Summary

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

(a) One (1) natural gas fired steam boiler, identified as SB-903, with backup capability to burn a blend of No. 1 or 2 fuel oils and biofuel, exhausting through SB-903, rated at 14.7 million British thermal units per hour, constructed and installed in 1997.

Under 40 CFR Part 60, Subpart Dc, this is considered an affected facility.

(b) One (1) natural gas fired steam boiler, known as SB-904, with backup capability to burn a blend of Nos. 1 or 2 fuel oils and biofuel, exhausted through Stack SB-904, rated at 21.0 million British thermal units per hour (500 horsepower), installed after 2000.

Under 40 CFR Part 60, Subpart Dc, this is considered an affected facility.

Note: **SB-903 and SB-904 are not subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ, because SB-903 and SB-904 are each considered natural gas-fired boilers as defined in 40 CFR 63.11237. Therefore these units are exempt from the requirements of 40 CFR 63, Subpart JJJJJJ, pursuant to 40 CFR 63.11195(e). At any time these facilities no longer meet the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the source shall comply with the applicable requirements of 40 CFR 63, Subpart JJJJJJ.**

...

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) natural gas fired steam boiler, identified as SB-903, with backup capability to burn a blend of No. 1 or 2 fuel oils and biofuel, exhausting through SB-903, rated at 14.7 million British thermal units per hour, constructed and installed in 1997.

(b) One (1) natural gas fired steam boiler, known as SB-904, with backup capability to burn a blend of Nos. 1 or 2 fuel oils and biofuel, exhausted through Stack SB-904, rated at 21.0 million British thermal units per hour (500 horsepower) installed after 2000.

Under 40 CFR Part 60, Subpart Dc, these are affected ~~sources~~ **facilities**.

Note: **SB-903 and SB-904 are not subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ, because SB-903 and SB-904 are each considered natural gas-fired boilers as defined in 40 CFR 63.11237. Therefore these units are exempt from the requirements of 40 CFR 63, Subpart JJJJJJ, pursuant to 40 CFR 63.11195(e). At any time these facilities no longer meet the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the source shall comply with the applicable requirements of 40 CFR 63, Subpart JJJJJJ.**

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

...

~~D.2.1 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]~~

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

~~(a) Equip the cleaner with a cover;~~

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

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

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

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

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

~~D.2.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-5]~~

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

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

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

~~(B) The solvent is agitated; or~~

~~(C) The solvent is heated.~~

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

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

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

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

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

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

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

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

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

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

~~(3) Store waste solvent only in covered containers and prohibit the disposal or transfer~~

~~of waste solvent in any manner in which greater than twenty percent (20%) of the waste solvent by weight could evaporate.~~

D.2.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control and Equipment Operating Requirements), the Permittee shall:

(a) 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 operating 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) 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 is 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.2.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, the Permittee shall not operate a cold cleaning degreaser with a solvent 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 Requirement [326 IAC 2-8-4(3)] [326 IAC 2-8-16]

D.2.3 Record Keeping Requirements

To document the compliance status with Condition D.1.3, on and after January 1, 2015, the Permittee shall maintain the following records for each purchase of solvent used in the cold cleaner degreasing operations. These records shall be retained on-site or accessible electronically for the most recent three (3) year period and shall be reasonably accessible for an additional two (2) year period.

(a) The name and address of the solvent supplier.

(b) The date of purchase.

(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).

…

SECTION E.1 FACILITY OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) natural gas fired steam boiler, identified as SB-903, with backup capability to burn a blend of No. 1 or 2 fuel oils and biofuel, exhausting through SB-903, rated at 14.7 million British thermal units per hour, constructed and installed in 1997.

(b) One (1) natural gas fired steam boiler, known as SB-904, with backup capability to burn a blend of Nos. 1 or 2 fuel oils and biofuel, exhausted through Stack SB-904, rated at 21.0 million British thermal units per hour (500 horsepower) installed after 2000.

Under 40 CFR Part 60, Subpart Dc, these units are considered affected facilities.

Note: SB-903 and SB-904 are not subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ, because SB-903 and SB-904 are each considered natural gas-fired boilers as defined in 40 CFR 63.11237. Therefore these units are exempt from the requirements of 40 CFR 63, Subpart JJJJJJ, pursuant to 40 CFR 63.11195(e). At any time these facilities no longer meet the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the source shall comply with the applicable requirements of 40 CFR 63, Subpart JJJJJJ.

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

...

...

All other conditions of the permit shall remain unchanged and in effect. Attached please find the entire revised permit.

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

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5. If you have any questions on this matter, please contact Nida Habeeb of my staff, at 317-234-8531 or 1-800-451-6027, and ask for extension 4-8531

Sincerely,

Jason R. Krawczyk, Section Chief
Permits Branch
Office of Air Quality

Attachments: Updated Permit and Appendix A

JK/NH

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
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Michael R. Pence
Governor
Thomas W. Easterly
Commissioner

Minor Source Operating Permit Renewal
OFFICE OF AIR QUALITY

Laketon Refining Corporation
2784 West Lukens Lake Road
Laketon, Indiana 46943

(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 to the above mentioned company under the provisions of 326 IAC 2-1.1, 326 IAC 2-6.1 and 40 CFR 52.780, with conditions listed on the attached pages.

Indiana statutes from IC 13 and rules from 326 IAC, quoted 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 MSOP under 326 IAC 2-6.1.

Operation Permit No.: M169-29989-00006	
Issued by: *Original Signed by:* Iryn Calilung, Section Chief Permits Branch Office of Air Quality	Issuance Date: June 24, 2011 Expiration Date: June 24, 2021

Administrative Amendment No.: 169-33207-00006	
Issued by: Jason Krawczyk, Section Chief Permits Branch Office of Air Quality	Issuance Date: June 21, 2013 Expiration Date: June 24, 2021

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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 and A.2 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 2-5.1-3(c)][326 IAC 2-6.1-4(a)]

The Permittee owns and operates a stationary asphalt liquid binder manufacturing source.

Source Address:	2784 West Lukens Lake Road, Laketon, Indiana 46943
General Source Phone Number:	260-982-2171
SIC Code:	2951
County Location:	Wabash
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Minor Source Operating Permit Program Minor Source, under PSD and Emission Offset Rules Minor Source, Section 112 of the Clean Air Act Not 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary

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

(a) One (1) natural gas fired steam boiler, identified as SB-903, with backup capability to burn a blend of No. 1 or 2 fuel oils and biofuel, exhausting through SB-903, rated at 14.7 million British thermal units per hour, constructed and installed in 1997.

Under 40 CFR Part 60, Subpart Dc, this is considered an affected facility.

(b) One (1) natural gas fired steam boiler, known as SB-904, with backup capability to burn a blend of Nos. 1 or 2 fuel oils and biofuel, exhausted through Stack SB-904, rated at 21.0 million British thermal units per hour (500 horsepower), installed after 2000.

Under 40 CFR Part 60, Subpart Dc, this is considered an affected facility.

Note: SB-903 and SB-904 are not subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ, because SB-903 and SB-904 are each considered natural gas-fired boilers as defined in 40 CFR 63.11237. Therefore these units are exempt from the requirements of 40 CFR 63, Subpart JJJJJJ, pursuant to 40 CFR 63.11195(e). At any time these facilities no longer meet the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the source shall comply with the applicable requirements of 40 CFR 63, Subpart JJJJJJ.

(c) One (1) natural gas hot oil heater, identified as HO-1, approved for construction in 2008, with a maximum heat input capacity of 8.0 MMBtu/hr, and a backup capacity to burn No. 2 fuel oil and biofuel.

(d) One (1) natural gas-fired internal hot oil tank heater, known as HO-2, exhausting to Stack HO-2, rated at 3.2 million British thermal units per hour.

(e) One (1) natural gas fired external asphalt tank (ST-029) heater, known as THE-930, constructed in 1956, rated at 7.15 million British thermal units per hour.

(f) One (1) asphalt cement loading rack, known as LR-1, with two loading spouts, each capable of loading 400 gallons per minute, or 48,000 gallons per hour.

(g) One (1) asphalt cement loading rack, known as LR-2, with two loading spouts, each capable of loading 400 gallons per minute, or 48,000 gallons per hour.

(h) One (1) asphalt cement and reuse solvent loading rack, constructed in 1997, known as LR-3, consisting of two (2) loading spouts for loading asphalt cement each with a capacity of 400 gallons per minute, or 48,000 gallons per hour, and one spout for loading reuse solvent, capable of loading 300 gallons per minute or 18,000 gallons per hour.

(i) Two (2) asphalt vertical fixed roof storage tanks, known as ST-009 and ST-010, constructed in 1895, and capacity: 1,470,000 gallons, each.

(j) One (1) heavy oils, kerosene, biofuel or asphalt storage tank, known as ST-021, constructed in 1975, capacity: 8,820 gallons.

(k) One (1) heavy oils, kerosene or asphalt internal floating roof storage tank, known as ST-007, constructed in 1956, capacity: 289,800 gallons.

(l) One (1) asphalt vertical fixed roof storage tank, known as ST-029, constructed in 1956, capacity: 428,400 gallons.

(m) One (1) asphalt vertical fixed roof storage tank, known as ST-061, constructed in 1985, capacity: 5,019,042 gallons.

(n) Four (4) asphalt vertical fixed roof storage tanks, known as ST-062, ST-063, ST-064, and ST-065, each approved for construction in 2013, capacity: 49,405 gallons each.

(o) One (1) petroleum asphalt products vertical fixed roof storage tank, known as ST-090, constructed in 1991, capacity: 30,000 gallons.

(p) Two (2) heavy oils or asphalt vertical fixed roof storage tanks, known as ST-091 and ST-092, constructed in 1991, capacity: 30,000 gallons, each.

(q) One (1) heavy oils or asphalt vertical fixed roof storage tank, known as ST-093, constructed in 1991, capacity: 30,000 gallons.

(r) Two (2) heavy oils or asphalt vertical fixed roof storage tanks, known as ST-094 and ST-095, constructed in 1994, capacity: 30,000 gallons, each.

(s) One (1) asphalt anti-stripping additive vertical fixed roof storage tank, known as ST-096, constructed in 1999, capacity: 13,000 gallons.

(t) One (1) asphalt vertical fixed roof storage tank, known as ST-060, constructed in 1985, capacity: 2,341,920 gallons.

(u) One (1) heating tank, known as ST-RR, exhausting to Stack ST-RR, capacity: 30,000 gallons of asphalt, throughput capacity: 400 gallons asphalt per minute.

(v) Degreasing operations that do not exceed 145 gallons per 12 months.

(w) Paved and unpaved roads and parking lots with public access.

(x) Eight (8) groundwater oil recovery systems, including one (1) rolling tube wick system and seven (7) rolling fabric wick systems, each with the capability of recovering one (1) gallon of oil per hour, both used on a sporadic basis for spill control, with no expected emissions. The systems operate in a closed building, and recovered oil is sent to an off-site disposal.

Below is a table summary of the tanks permitted at this source.

Tank I.D.	Material Stored	Construction Date	Capacity (gallons)	Type of Tank (e.g. vertical fixed roof)
ST-009	Asphalt	1895	1,470,000	vertical fixed roof
ST-010	Asphalt	1895	1,470,000	vertical fixed roof
ST-007	Oils, Reuse solvent	1956	289,800	internal floating roof
ST-029	Asphalt	1956	428,400	vertical fixed roof
ST-062	Asphalt	2013	49,405	vertical fixed roof
ST-063	Asphalt	2013	49,405	vertical fixed roof
ST-064	Asphalt	2013	49,405	vertical fixed roof
ST-065	Asphalt	2013	49,405	vertical fixed roof
ST-021	Oils, kerosene	1975	8,820	vertical fixed roof
ST-060	Asphalt	1985	2,341,920	vertical fixed roof
ST-061	Asphalt	1985	5,019,042	vertical fixed roof
ST-090	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-091	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-092	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-093	Oils, asphalt products	1991	30,000	vertical fixed roof
ST-094	Oils, asphalt products	1994	30,000	vertical fixed roof
ST-095	Oils, asphalt products	1994	30,000	vertical fixed roof
ST-096	Anti-stripping Additive	1999	13,000	vertical fixed roof

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-1.1-1]

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 2-1.1-1) shall prevail.

B.2 Permit Term [326 IAC 2-6.1-7(a)][326 IAC 2-1.1-9.5][IC 13-15-3-6(a)]

(a) This permit, M169-29989-00006, is issued for a fixed term of ten (10) 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.

(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, 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

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

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

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

B.7 Duty to Provide Information

(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 Annual Notification [326 IAC 2-6.1-5(a)(5)]

(a) An annual notification shall be submitted by an authorized individual to the Office of Air Quality stating whether or not the source is in operation and in compliance with the terms and conditions contained in this permit.

(b) The annual notice shall be submitted in the format attached no later than March 1 of each year to:

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

(c) The notification 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.

B.9 Preventive Maintenance Plan [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 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.

(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.10 Prior Permits Superseded [326 IAC 2-1.1-9.5]

(a) All terms and conditions of permits established prior to M169-29989-00006 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised, or

(3) deleted.

(b) All previous registrations and permits are superseded by this permit.

B.11 Termination of Right to Operate [326 IAC 2-6.1-7(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 one hundred twenty (120) days prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-6.1-7.

B.12 Permit Renewal [326 IAC 2-6.1-7]

(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 2-6.1-7. Such information shall be included in the application for each emission unit at this source. The renewal application does require an affirmation that the statements in the application are true and complete by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

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 one hundred twenty (120) days 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 2-6.1 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 2-6.1-4(b), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.13 Permit Amendment or Revision [326 IAC 2-5.1-3(e)(3)][326 IAC 2-6.1-6]

(a) Permit amendments and revisions are governed by the requirements of 326 IAC 2-6.1-6 whenever the Permittee seeks to amend or modify this permit.

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

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

(c) The Permittee shall notify the OAQ no later than thirty (30) calendar days of implementing a notice-only change. [326 IAC 2-6.1-6(d)]

B.14 Source Modification Requirement

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

B.15 Inspection and Entry
[326 IAC 2-5.1-3(e)(4)(B)][326 IAC 2-6.1-5(a)(4)][IC 13-14-2-2][IC 13-17-3-2][IC 13-30-3-1]

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

(a) Enter upon the Permittee's premises where a permitted 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, at reasonable times, 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, at reasonable times, 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, at reasonable times, 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.16 Transfer of Ownership or Operational Control [326 IAC 2-6.1-6]

(a) The Permittee must comply with the requirements of 326 IAC 2-6.1-6 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

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

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

The application which shall be submitted by the Permittee does require an affirmation that the statements in the application are true and complete by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(c) The Permittee may implement notice-only changes addressed in the request for a notice-only change immediately upon submittal of the request. [326 IAC 2-6.1-6(d)(3)]

B.17 Annual Fee Payment [326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees due no later than thirty (30) calendar days of receipt of a bill from IDEM, OAQ,.

(b) 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.18 Credible Evidence [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 2-6.1-5(a)(1)]

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

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

C.2 Permit Revocation [326 IAC 2-1.1-9]

Pursuant to 326 IAC 2-1.1-9 (Revocation of Permits), this permit to operate may be revoked for any of the following causes:

(a) Violation of any conditions of this permit.

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this permit.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this permit shall not require revocation of this permit.

(d) Noncompliance with orders issued pursuant to 326 IAC 1-5 (Episode Alert Levels) to reduce emissions during an air pollution episode.

(e) For any cause which establishes in the judgment of IDEM, the fact that continuance of this permit is not consistent with purposes of this article.

C.3 Opacity [326 IAC 5-1]

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

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

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

C.4 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 using ambient air quality modeling pursuant to 326 IAC 1-7-4.

C.5 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.6 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.7 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).

C.8 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.

(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 2-6.1-5(a)(2)]

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

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

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

no later than thirty-five (35) days prior to the intended test date.

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date.

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

Compliance Requirements [326 IAC 2-1.1-11]

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

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

Compliance Monitoring Requirements [326 IAC 2-6.1-5(a)(2)]

C.11 Compliance Monitoring [326 IAC 2-1.1-11]

Compliance with applicable requirements shall be documented as required by this permit. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. All monitoring and record keeping requirements not already legally required shall be implemented when operation begins.

C.12 Instrument Specifications [326 IAC 2-1.1-11]

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

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

Corrective Actions and Response Steps

C.13 Response to Excursions or Exceedances

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

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

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

(1) initial inspection and evaluation;

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

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

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

C.14 Actions Related to Noncompliance Demonstrated by a Stack Test

(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.

Record Keeping and Reporting Requirements [326 IAC 2-6.1-5(a)(2)]

C.15 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, including startups or shutdowns of any facility or emission control equipment, which result in violations of applicable air pollution control regulations or applicable emission limitations shall be kept and retained for a period of three (3) years and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) or appointed representative upon request.

(b) When a malfunction of any facility or emission control equipment occurs which lasts more than one (1) hour, said condition shall be reported to OAQ, using the Malfunction Report Forms (2 pages). Notification shall be made by telephone or facsimile, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of said occurrence.

(c) Failure to report a malfunction of any emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction shall be provided, including the items specified in 326 IAC 1-6-2(a)(1) through (6).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

C.16 General Record Keeping Requirements [326 IAC 2-6.1-5]

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

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

C.17 General Reporting Requirements [326 IAC 2-1.1-11] [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) Reports required by conditions in Section D of this permit shall be submitted to:

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

(b) 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.

(c) 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.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) natural gas fired steam boiler, identified as SB-903, with backup capability to burn a blend of No. 1 or 2 fuel oils and biofuel, exhausting through SB-903, rated at 14.7 million British thermal units per hour, constructed and installed in 1997.

(b) One (1) natural gas fired steam boiler, known as SB-904, with backup capability to burn a blend of Nos. 1 or 2 fuel oils and biofuel, exhausted through Stack SB-904, rated at 21.0 million British thermal units per hour (500 horsepower) installed after 2000.

Under 40 CFR Part 60, Subpart Dc, these are affected facilities.

Note: SB-903 and SB-904 are not subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ, because SB-903 and SB-904 are each considered natural gas-fired boilers as defined in 40 CFR 63.11237. Therefore these units are exempt from the requirements of 40 CFR 63, Subpart JJJJJJ, pursuant to 40 CFR 63.11195(e). At any time these facilities no longer meet the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the source shall comply with the applicable requirements of 40 CFR 63, Subpart JJJJJJ.

(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 2-6.1-5(a)(1)]

D.1.1 Particulate [326 IAC 6-2]

(a) Pursuant to 326 IAC 6-2-4, (Emission limitations specified in 326 IAC 6-2-1(c)), particulate matter (PM) emissions from steam boiler SB-903, constructed in 1997, rated at 14.7 million British thermal units per hour, burning natural gas, No. 1 or No. 2 oil or biofuel shall be limited to that determined by the following equation.

$$Pt = 1.09 / Q^{0.26}$$

Where: Pt = Particulate emission limitation, expressed in lb/MMBtu; and
Q = the total source maximum operating capacity in million British thermal units per hour (14.7 MMBtu/hr for SB-903).

Pursuant to 326 IAC 6-2-4, (Emission limitations specified in 326 IAC 6-2-4(d)), PM emissions from steam boiler SB-903, used for indirect purposes shall not exceed 0.54 pounds of particulate matter per million British thermal units heat input.

(b) Pursuant to 326 IAC 6-2-4, (Emission limitations specified in 326 IAC 6-2-1(c)), particulate matter (PM) emissions from steam boiler SB-904, constructed after 2000, rated at 21.0 million British thermal units per hour, burning natural gas, No. 1 or No. 2 oil or biofuel shall be limited to that determined by the following equation.

$$Pt = 1.09 / Q^{0.26}$$

Where: Pt = Particulate emission limitation, expressed in lb/MMBtu; and
Q = the total source maximum operating capacity in million British thermal units per hour (21.0 MMBtu/hr for SB-904).

Pursuant to 326 IAC 6-2-4, (Emission limitations specified in 326 IAC 6-2-4(d)), PM emissions from steam boiler SB-904, used for indirect purposes shall not exceed 0.43 pounds of particulate matter per million British thermal units heat input, respectively.

D.1.2 Sulfur Dioxide (SO_2) [326 IAC 7-1.1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1-2 (SO_2 Emissions Limitations), the SO_2 emissions from steam boilers, SB-903 and SB-904, each shall not exceed five tenths (0.5) pounds per MMBtu heat input, from the combustion of distillate fuel oil and biofuel, which is equivalent to five-tenths percent (0.5%) by weight.

Note: No. 1 and No. 2 fuel oils are considered distillate oil.

D.1.3 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan is required for this facility and its control device. Section B - Preventive Maintenance, contains the Permittee's obligation with regard to this condition.

Compliance Determination Requirements

D.1.4 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition D.1.2 shall be determined utilizing one of the following options:

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pound per million Btu heat input by:

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

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the boiler using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

A determination of noncompliance pursuant to any of the methods specified in (a) or (b) above shall not be refuted by evidence of compliance pursuant to the other method.

Compliance Monitoring Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.5 Visible Emissions Notations

(a) Visible emission notations of the steam boiler units, SB-903 and SB-904, exhaust shall be performed once per day during normal daylight operations while combusting fuel oil and biofuel. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Section C- Response to Excursions or Exceedances contains the Permittee's obligation with regard to this condition. Failure to take response steps shall be considered a deviation from this permit.

Record Keeping and Reporting Requirement [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.6 Record Keeping Requirements

(a) To document the compliance status with Condition D.1.2, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.1.2.

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

(2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

(3) To certify compliance when burning natural gas only, the Permittee shall maintain records of fuel used.

If the fuel supplier certification is used to demonstrate compliance, when burning alternate fuels and not determining compliance pursuant to 326 IAC 3-7-4, the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and

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

Pursuant to 326 IAC 7-2-1(c)(3),the Permittee shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per MMBtu upon request.

(b) To document the compliance status with Condition D.1.5, the Permittee shall maintain daily records of visible emission notations of the boiler stacks SB-903 and SB-904 exhaust while combusting fuel oil and biofuel. 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 (i.e., the process did not operate that day).

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

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(v) Degreasing operations that do not exceed 145 gallons per 12 months.

(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 (Cold Cleaning Degreaser Operations)

D.2.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control and Equipment Operating Requirements), the Permittee shall:

(a) 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 operating 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) 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 is 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.2.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, the Permittee shall not operate a cold cleaning degreaser with a solvent 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 Requirement [326 IAC 2-8-4(3)] [326 IAC 2-8-16]

D.2.3 Record Keeping Requirements

To document the compliance status with Condition D.1.3, on and after January 1, 2015, the Permittee shall maintain the following records for each purchase of solvent used in the cold cleaner degreasing operations. These records shall be retained on-site or accessible electronically for the most recent three (3) year period and shall be reasonably accessible for an additional two (2) year period.

(a) The name and address of the solvent supplier.

(b) The date of purchase.

(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).

SECTION E.1 FACILITY OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) natural gas fired steam boiler, identified as SB-903, with backup capability to burn a blend of No. 1 or 2 fuel oils and biofuel, exhausting through SB-903, rated at 14.7 million British thermal units per hour, constructed and installed in 1997.

(b) One (1) natural gas fired steam boiler, known as SB-904, with backup capability to burn a blend of Nos. 1 or 2 fuel oils and biofuel, exhausted through Stack SB-904, rated at 21.0 million British thermal units per hour (500 horsepower) installed after 2000.

Under 40 CFR Part 60, Subpart Dc, these units are considered affected facilities.

Note: SB-903 and SB-904 are not subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ, because SB-903 and SB-904 are each considered natural gas-fired boilers as defined in 40 CFR 63.11237. Therefore these units are exempt from the requirements of 40 CFR 63, Subpart JJJJJJ, pursuant to 40 CFR 63.11195(e). At any time these facilities no longer meet the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the source shall comply with the applicable requirements of 40 CFR 63, Subpart JJJJJJ.

(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 12-1]

E.1.1 General Provisions Relating to New Source Performance Standards (NSPS) under 40 CFR Part 60 [326 IAC 12-1] [40 CFR Part 60, Subpart Dc]

(a) Pursuant to 40 CFR 60.40c, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart Dc – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the steam generating boiler units, used for indirect heating, identified as SB-903 and SB-904.

(b) Pursuant to 40 CFR 60, Subpart Dc, the Permittee shall submit all required notifications and reports to:

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

E.1.2 New Source Performance Standards (NSPS), Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Dc]

Pursuant to 40 CFR 60, Subpart Dc, the Permittee shall comply with the provisions of 40 CFR 60, Subpart Dc, for the steam generating boiler units, used for indirect heating, identified as SB-903 and SB-904, as specified as follows. Applicable portions are listed below. The Subpart is listed in its entirety in Attachment A of this permit.

(a) 40 CFR 60.40c
(b) 40 CFR 60.41c
(c) 40 CFR 60.42c(d)
(d) 40 CFR 60.42c(f)(2)

(e) 40 CFR 60.42c(g)
(f) 40 CFR 60.42c(h)(1)
(g) 40 CFR 60.42c(i)
(h) 40 CFR 60.42c(j)
(i) 40 CFR 60.44c(h)
(j) 40 CFR 60.43c
(k) 40 CFR 60.45c
(l) 40 CFR 60.48c(a)
(m) 40 CFR 60.48c(b)
(n) 40 CFR 60.48c(d)
(o) 40 CFR 60.48c(f)(1)
(p) 40 CFR 60.48c(g)
(q) 40 CFR 60.48c(i)
(r) 40 CFR 60.48c(j)

E.1.3 Testing Requirements [326 IAC 2-1.1-11]

The Permittee shall perform the stack testing as required under NSPS 40 CFR 60, Subpart Dc, utilizing methods as approved by the Commissioner to document compliance with Condition E.1.2 These tests shall be repeated at least once every five (5) years from the date of the last valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

MINOR SOURCE OPERATING PERMIT
ANNUAL NOTIFICATION

This form should be used to comply with the notification requirements under 326 IAC 2-6.1-5(a)(5).

Company Name:	Laketon Refining Corporation
Address:	2784 West Lukens Lake Road
City:	Laketon, Indiana 46943
Phone #:	260-982-2171
MSOP #:	M169-29989-00006

I hereby certify that Laketon Refining Corporation is :
☐ still in operation.
☐ no longer in operation.

I hereby certify that Laketon Refining Corporation is :
☐ in compliance with the requirements of MSOP M169-29989-00006.
☐ not in compliance with the requirements of MSOP M169-29989-00006.

Authorized Individual (typed):
Title:
Signature:
Date:

If there are any conditions or requirements for which the source is not in compliance, provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be achieved.

Noncompliance:

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
FAX NUMBER: (317) 233-6865

<u>This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.</u>

THIS FACILITY MEETS THE APPLICABILITY REQUIREMENTS BECAUSE IT HAS POTENTIAL TO EMIT 25 TONS/YEAR PARTICULATE MATTER ?_____, 25 TONS/YEAR SULFUR DIOXIDE ?_____, 25 TONS/YEAR NITROGEN OXIDES?_____, 25 TONS/YEAR VOC ?_____, 25 TONS/YEAR HYDROGEN SULFIDE ?_____, 25 TONS/YEAR TOTAL REDUCED SULFUR ?_____, 25 TONS/YEAR REDUCED SULFUR COMPOUNDS ?_____, 25 TONS/YEAR FLUORIDES ?_____, 100 TONS/YEAR CARBON MONOXIDE ?_____, 10 TONS/YEAR ANY SINGLE HAZARDOUS AIR POLLUTANT ?_____, 25 TONS/YEAR ANY COMBINATION HAZARDOUS AIR POLLUTANT ?_____, 1 TON/YEAR LEAD OR LEAD COMPOUNDS MEASURED AS ELEMENTAL LEAD ?_____, OR IS A SOURCE LISTED UNDER 326 IAC 2-5.1-3(2) ?_____. EMISSIONS FROM MALFUNCTIONING CONTROL EQUIPMENT OR PROCESS EQUIPMENT CAUSED EMISSIONS IN EXCESS OF APPLICABLE LIMITATION ________.

THIS MALFUNCTION RESULTED IN A VIOLATION OF: 326 IAC _______ OR, PERMIT CONDITION # _______ AND/OR PERMIT LIMIT OF _______________

THIS INCIDENT MEETS THE DEFINITION OF "MALFUNCTION" AS LISTED ON REVERSE SIDE ? Y N

THIS MALFUNCTION IS OR WILL BE LONGER THAN THE ONE (1) HOUR REPORTING REQUIREMENT ? Y N

COMPANY:____PHONE NO. ( )__________________
LOCATION: (CITY AND COUNTY)____
PERMIT NO. ________________ AFS PLANT ID: ________________ AFS POINT ID: ________________ INSP:__________
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON:____
____

DATE/TIME MALFUNCTION STARTED: _____/_____/ 20____ ____ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION: ______________________________________

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE______/______/ 20____ _______________ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO2, VOC, OTHER:_______________________________________

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: _______________________________________
____

MEASURES TAKEN TO MINIMIZE EMISSIONS:____
____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

CONTINUED OPERATION REQUIRED TO PROVIDE <u>ESSENTIAL</u>* SERVICES:____________________________________
CONTINUED OPERATION NECESSARY TO PREVENT INJURY TO PERSONS:____________________________________
CONTINUED OPERATION NECESSARY TO PREVENT SEVERE DAMAGE TO EQUIPMENT:__________________________
INTERIM CONTROL MEASURES: (IF APPLICABLE)____
____
____

MALFUNCTION REPORTED BY:__________________________________TITLE:___________________________
(SIGNATURE IF FAXED)

MALFUNCTION RECORDED BY:_______________________DATE:_________________TIME:__________________
*SEE PAGE 2

Please note - This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1 or 326 IAC 2-6.1.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

***Essential services** are interpreted to mean those operations, such as, the providing of electricity by power plants. Continued operation solely for the economic benefit of the owner or operator shall not be sufficient reason why a facility cannot be shutdown during a control equipment shutdown.

If this item is checked on the front, please explain rationale:

____
____

Attachment A

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/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(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) Heat recovery steam generators that are associated with combined cycle gas 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 that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 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.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

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) or 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).

Dry flue gas desulfurization technology means a SO_2control 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_2control 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_2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

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.

Wet flue gas desulfurization technology means an SO_2control 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]

§ 60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in 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_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in 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_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of SO_2in 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_2emissions limit or the 90 percent SO_2reduction 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_2emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 50 percent (0.50) of the potential SO_2emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in 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_2reduction 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_2in 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/hr) 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.

(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_2in excess of 215 ng/J (0.50 lb/MMBtu) heat input; 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_2in excess of the following:

(1) The percent of potential SO_2emission rate or numerical SO_2emission 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/hr); 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_2emission 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_2emission 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_2emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2control) 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), or (3) 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 facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The SO_2emission 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]

§ 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/hr) 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/hr) 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 can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) 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.

(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/hr) 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/hr) 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) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility 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_2emissions 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]

§ 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_2emission 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_2emission limits under §60.42c is based on the average percent reduction and the average SO_2emission 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_2emission 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_2emission rate (E_{ho}) and the 30-day average SO_2emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate $E_{ao}$when using daily fuel sampling or Method 6B of appendix A of this part.

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

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

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

Where:

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

E_{ho}= Hourly SO_2emission rate, ng/J (lb/MMBtu);

E_w= SO_2concentration in fuels other than coal and oil combusted in the affected facility, as determined by 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:

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

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_2standards 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_2standards 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_2emissions 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.

Link to an amendment published at 76 FR 3523, Jan. 20, 2011.

(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_2or CO_2measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

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

(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) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For 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) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

(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/hr).

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

§ 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_2emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations at the outlet of the SO_2control device (or the outlet of the steam generating unit if no SO_2control 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_2concentrations and either O_2or CO_2concentrations at both the inlet and outlet of the SO_2control device.

(b) The 1-hour average SO_2emission 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_2emission 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_2emission 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_2CEMS at the inlet to the SO_2control device shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted, and the span value of the SO_2CEMS at the outlet from the SO_2control device shall be 50 percent of the maximum estimated hourly potential SO_2emission 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_2CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission 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_2input 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_2at the inlet or outlet of the SO_2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$and CO_2measurement train operated at the candidate location and a second similar train operated according to the procedures in §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_2standards 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.

Link to an amendment published at 76 FR 3523, Jan. 20, 2011.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) 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) and that is not required to install a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to install a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

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

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

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

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

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

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

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.* , 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.* , 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (a) of this section within 30 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

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

(b) 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) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

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

§ 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_2emissions. 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_2emission 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_2emission 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_2emission 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_2emission 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_2emission 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_2or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and 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_2standard, 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_2standard, 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]

Appendix A: Emissions Calculations
Emissions Summary

Company Name: Laketon Refining Corporation
Address City IN Zip: 2784 West Lukens Lake Road, Laketon, IN 46943
Permit Number: M169-33207-00006
Plt ID: 169-00006
Reviewer: Nida Habeeb
Date: May 24, 2013

Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	*CO2e	Worst HAP	Total HAPs	
Combustion Sources Natural Gas with No.1, No2, Biofuel as back-up Boiler SB-903, Boiler SB-904, Heater HO-1											
Natural Gas	0.4	1.5	1.5	0.1	19.1	1.1	16.1	23,109	3.45E-01	3.60E-01	Hexane
No. 1 Fuel, No. 2 Fuel	2.7	2.7	2.7	97.1	27.3	0.5	6.8	23,109	2.87E-03	9.40E-03	Selenium
Biofuel	2.7	2.7	2.7	97.1	30.1	0.5	6.8	23,109	2.87E-03	9.40E-03	Selenium
WORST CASE FUEL	**2.7**	**2.7**	**2.7**	**97.1**	**30.1**	**1.1**	**16.1**	**23,109**	**3.45E-01**	**3.60E-01**	**Hexane**
Combustion Sources Natural Gas Only Heater THE-930, Heater HO-2	0.1	0.3	0.3	0.0	4.5	0.2	3.8	0	8.16E-02	8.60E-02	Hexane
Loading Racks LR-1, LR-2, LR-3	0.0	0.0	0.0	0.0	0.0	2.18E-01	0.0	0.0	0.0	0.0	
VOC Emissions from Tanks	0.0	0.0	0.0	0.0	0.0	3.800E-02	0.0	0.0	0.0	0.0	
VOC Emissions from Misc. Sources	0.0	0.0	0.0	0.0	0.0	5.52E-01	0.0	0.0	0.0	0.0	
Total Uncontrolled Emissions	**2.8**	**3.0**	**3.0**	**97.1**	**34.6**	**2.11**	**19.9**	**23,109**	**4.26E-01**	**0.446**	**Hexane**

*The 100,000 CO_2e threshold represents the Title V and PSD subject to regulation thresholds for GHGs in order to determine whether a source's emissions are a regulated NSR pollutant under Title V and PSD.

Pursuant to 326 IAC 2-7-1(39), starting July 1, 2011, greenhouse gases (GHGs) emissions are subject to regulation at a source with a potential to emit (PTE) 100,000 tons per year or more of CO2 equivalent emissions (CO2e). Therefore, CO2e emissions have been calculated for this source. Based on the calculations, the unlimited PTE GHGs from the entire source is less than 100,000 tons of CO2e per year (see Appendix A for the calculations). This did not require any changes to the permit

Appendix A: Emissions Calculations
Appendix A: Emissions Calculations
MM BTU/HR <100

Company Name: Laketon Refining Corporation
Address City IN Zip: 2784 West Lukens Lake Road, Laketon, IN 46943
Permit Number: M169-33207-00006
Plt ID: 169-00006
Reviewer: Nida Habeeb
Date: May 24, 2013

Comb. Unit	MMBtu/hr
SB-903	14.70
SB-904	21.00
HO-1	8.00
Subtotal	43.70
THE-930	7.15
HO-2	3.20
Subtotal	10.35

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
43.70	1000	382.8

SB-903, SB-904, HO-1	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	0.6	100 **see below	5.5	84
SB-903	0.1	0.5	0.0	6.4	0.4	5.4
SB-904	0.2	0.7	0.1	9.2	0.5	7.7
HO-1	0.1	0.3	0.0	3.5	0.2	2.9
Potential Emission in tons/yr	0.4	1.5	0.1	19.1	1.1	16.1

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined. PM2.5=PM10.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
10.35	1000	90.7

THE-930, HO-2	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	0.1	0.3	0.0	4.5	0.2	3.8

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/1,000 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
Emission (lb/MMBtu)=emission (tons/yr)/8769 (hr/yr)*2000 (lb/ton)*0.14.
See page 3 for HAPs emissions calculations.

updated 12/10

Appendix A: Emissions Calculations
MM BTU/HR <100

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24, 2013**

SB-903, SB-904, HO-1	HAPs - Organics					Worst	Total
	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	4.020E-04	2.297E-04	1.436E-02	3.445E-01	6.508E-04	**Hexane 3.445E-01**	3.602E-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	9.570E-05	2.105E-04	2.680E-04	7.273E-05	4.020E-04	Nickel 4.020E-04	1.049E-03
						TOTALS	**3.6E-01**

THE-930, HO-2	HAPs - Organics					Worst	Total
	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	9.520E-05	5.440E-05	3.400E-03	8.160E-02	1.541E-04	**Hexane 8.160E-02**	8.530E-02

	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	2.267E-05	4.987E-05	6.347E-05	1.723E-05	9.520E-05	Nickel 9.520E-05	2.484E-04
						TOTALS	**8.6E-02**

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
MM BTU/HR <100

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24, 2013**

Greenhouse Gas Emissions

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120000	2.3	2.2
Potential Emission in tons/yr	22,969	0.44	0.42
Summed Potential Emissions in tons/yr	22,970		
CO2e Total in tons/yr	23,109		

Methodology:
The N2O Emission Factor for uncontrolled is 2.2.
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.
Greenhouse 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 (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)
#1 and #2 Fuel Oil

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24,2013**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput kgals/year		S = Weight % Sulfur	Potential Throughput MMCF/yr
14.7		919.80	**SB-903**	0.5	382.812
21.0	1000	1314.00	**SB-904**	0.5	
8.0		500.57	**HO-1**	0.5	
43.7		2734.37			

	Pollutant				
	PM*	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	71.0 *(142.0S)*	20.0	0.34	5.0
Potential Emission in tons/yr	2.7	97.1	27.3	0.5	6.8

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-03-005-01/02/03) Supplement E 9/98 (see erata file)

*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)
#1 and #2 Fuel Oil
HAPs Emissions

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24,2013**

	HAPs - Metals					Worst	Total
	Arsenic	Beryllium	Cadmium	Chromium	Lead		
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06		
Potential Emission in tons/yr	7.66E-04	5.74E-04	5.74E-04	5.74E-04	1.72E-03	**Lead** **1.723E-03**	4.211E-03

	HAPs - Metals (continued)					
	Mercury	Manganese	Nickel	Selenium		
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05		
Potential Emission in tons/yr	5.74E-04	1.15E-03	5.74E-04	2.87E-03	Selenium 2.871E-03	5.168E-03
					TOTALS	**9.4E-03**

Methodology

No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emissions Calculations
MM BTU/HR <100
Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24, 2013**

Greenhouse Gas Emissions

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor in lb/MMcf	120000	2.3	2.2
Potential Emission in tons/yr	22,969	0.44	0.42
Summed Potential Emissions in tons/yr	22,970		
CO_2e Total in tons/yr	23,109		

Methodology:
The N_2O Emission Factor for uncontrolled is 2.2.
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.
Greenhouse 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
CO_2e (tons/yr) = CO_2 Potential Emission ton/yr x CO_2 GWP (1) + CH_4 Potential Emission ton/yr x CH_4 GWP (21) + N_2O Potential Emission ton/yr x N_2O GWP (310).

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)
Biofuel Combustion Units

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24,2013**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput kgals/year		S = Weight % Sulfur	Potential Throughput MMCF/yr
14.7		919.80	**SB-903**	0.5	382.812
21.0	1000	1314.00	**SB-904**	0.5	
8.0		500.57	**HO-1**	0.5	
43.7		2734.37			

	Pollutant				
	PM*	SO2	NOx**	VOC	CO
Emission Factor in lb/kgal	2.0	71.0 *(142.0S)*	22.0	0.34	5.0
Potential Emission in tons/yr	2.7	97.1	30.1	0.5	6.8

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

** Since there are no specific AP-42 emission factors for combustion of Biofuel, a worst-case scenario was assumed where PM, PM10, PM2.5, SO2, VOC, VO, and HAP emissions are he same as from combustion of No. 2 fuel oil, and based on the US EPA draft technical report titled "A Comprehensive Analysis of Biofuel Impacts on Exhaust Emissions, dated October, 2002, in which NOx emissions are 10% greater than those from No. 2 Fuel Oil. This was done to allow the source to use any grade of biofuel available, maximizing operational flexibility. Therefore, the NOx emission factor is 20.0 +10% = 22.0.

*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.

Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

See page 7 for HAPs emission calculations.

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)
#1 and #2 Fuel Oil
HAPs Emissions

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24,2013**

	HAPs - Metals					Worst	Total
	Arsenic	Beryllium	Cadmium	Chromium	Lead		
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06		
						Lead	
Potential Emission in tons/yr	7.66E-04	5.74E-04	5.74E-04	5.74E-04	1.72E-03	**1.723E-03**	4.211E-03

	HAPs - Metals (continued)					
	Mercury	Manganese	Nickel	Selenium		
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05		
					Selenium	
Potential Emission in tons/yr	5.74E-04	1.15E-03	5.74E-04	2.87E-03	2.871E-03	5.168E-03
					TOTALS	**9.4E-03**

Methodology

No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Appendix A: Emissions Calculations
MM BTU/HR <100

Company Name: Laketon Refining Corporation
Address City IN Zip: 2784 West Lukens Lake Road, Laketon, IN 46943
Permit Number: M169-33207-00006
Plt ID: 169-00006
Reviewer: Nida Habeeb
Date: May 24, 2013

Greenhouse Gas Emissions

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120000	2.3	2.2
Potential Emission in tons/yr	22,969	0.44	0.42
Summed Potential Emissions in tons/yr	22,970		
CO2e Total in tons/yr	23,109		

Methodology:

The N2O Emission Factor for uncontrolled is 2.2.

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.

Greenhouse 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 (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emission Calculations
VOC Emissions from Loading Racks

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24, 2013**

1. Emission Factors: AP-42

The following calculations determine the amount of emissions created by ballasting, based on 8760 hours per year use, and emiissions factors from AP-42 Chapter 5.2-4, Total Organic Emission Factors for Crude Oil Ballasting

$$L_L = 12.46 \times (S \times P \times M) / T$$

where:

L_L = loading loss (lbs/kgal)
S = a saturation factor (see AP-42, Table 5.2-1)
P = true vapor pressure of the liquid loaded (psia)
M = molecular weight of vapors
T = temperature of the bulk liquid loaded (degree R)

Loading Rack and Material	S	P (psia)	M (lbs/mole lbs)	T (degree R)	L_L (lbs/kgal)	L_L (lbs/gal)
LR-1 Asphalt cement loading	1.45	1.9E-09	3.2	7.6	1.45E-08	1.45E-11
LR-2 Asphalt cement loading	1.45	1.9E-09	3.2	7.6	1.45E-08	1.45E-11
LR-3 Asphalt cement loading	1.45	1.9E-09	3.2	7.6	1.45E-08	1.45E-11

2. Potential to Emit VOC Before Control:

Loading Rack and Material	L_L (lbs/gal)	Gallons/hr Capacity	VOC Emissions (lbs/hr)	VOC Emissions (lbs/yr)	VOC Emissions (tons / yr)
LR-1 Asphalt cement loading	1.45E-11	96000	1.39E-06	1.22E-02	6.08E-06
LR-2 Asphalt cement loading	1.45E-11	96000	1.39E-06	1.22E-02	6.08E-06
LR-3 Aspahlt cement loading	1.45E-11	96000	1.39E-06	1.22E-02	6.08E-06
LR-3 Reuse solvent loading	1.45E-11	18000	2.61E-07	2.29E-03	1.14E-06
TOTALS			4.16E-06	3.65E-02	1.82E-05

Total VOC Emissions from Loading Rack **2.18E-01**

VOC Emissions lb/hr = Loading loss (lbs/gallon) x maximum loading rack capacity (gallons/hr)
VOC Emissions lbs/yr = VOC emissions (lbs/hr) x 8760 hours/year
VOC Emissions tons/yr = VOC emissions (lbs/yr) / 2000 (lbs/ton)

Appendix A: Emission Calculations
VOC Emissions from Miscellaneous Operations

Company Name: **Laketon Refining Corporation**
Address City IN Zip: **2784 West Lukens Lake Road, Laketon, IN 46943**
Permit Number: **M169-33207-00006**
Plt ID: **169-00006**
Reviewer: **Nida Habeeb**
Date: **May 24, 2013**

The following calculations determine the amount of emissions created by
fugitive emissions from transfer (Valves, pumps, seals, and flanges), based on 8760 hours of use and *AP-42, Ch 5.1, Fugitive Emissions from Petroleum Refineries, (ref US EPA-453/R-95-017)*

Assumptions:

2 Valves/tank X 26 tanks	1 pump/tank x 26 tanks	2 flanges/pump&valve X (80 valves+40 pumps)
2 Valves/loading rack X 3 racks	2 pumps/rack x 3 racks	8 open connections (unloading stations)
2 Valves/truck unloading pump X 4 unloading pumps	4 rail unloading pumps	**Total # of flanges+connections = 248**
2 Valves/rail unloading pump X 4 unloading pumps	4 unloading pumps	
6 other valves	4 other pumps	
Total # of Valves = 80	**Total # of Pumps = 40**	

VOC Emissions:

Valve Emissions = 5.06E-05 lb VOC/hr - valve x 8760 hrs/yr x 80 valves = 35.461 lb VOC/yr.

Pump Emissions = 2.97E-03 lb VOC/hr - valve x 8760 hrs/yr x 40 pumps = 1040.688 lb VOC/yr.

Flange Emissions = 1.32E-05 lb VOC/hr - valve x 8760 hrs/yr x 248 flanges = 28.677 lb VOC/yr.

Total VOC Miscellaneous Emissions: 1,104.826 lbs. = 0.552 tons VOC/year

Methodology:

Emission factors for fugitive leaks from the following types of process equipment can be found in *Protocol For Equipment Leak Emission Estimates* , EPA-453/R-93-026, June 1993, or subsequent updates, as referenced in AP-42, Chapter 5.1, Fugitive Emissions from Petroleum Refineries:
- Valves
- Flanges
- Seals of pumps
- Process Drains

Valve fugitive emissions (lb/yr) = emission factor (lb VOC/hr) x 8760 hrs/yr x number of valves
Valve fugitive emissions (tons/yr) = valve fugitive emissions (lb/yr) / 2000 lb/ton

Pump fugitive emissions (lb/yr) = emission factor (lb VOC/hr) x 8760 hrs/yr x number of valves
Pump fugitive emissions (tons/yr) = pump fugitive emissions (lb/yr) / 2000 lb/ton

Flange fugitive emissions (lb/yr) = emission factor (lb VOC/hr) x 8760 hrs/yr x number of valves
Flange fugitive emissions (tons/yr) = flange fugitive emissions (lb/yr) / 2000 lb/ton

Appendix A: Emission Calculations
VOC Emissions From Storage Tanks

Company Name: Laketon Refining Corporation
Address City IN Zip: 2784 West Lukens Lake Road, Laketon, IN 46943
Permit Number: M169-33207-00006
Plt ID: 169-00006
Reviewer: Nida Habeeb
Date: May 24, 2013

Tank I.D.	Material Stored	Construction Date	Capacity (gallons)	Type of Tank (e.g. vertical fixed roof)	Tank Diameter (ft)	Tank Height (ft)	Temperature (deg. C)	Vapor Pressure Provided by Source (psi)	Vapor Pressure Used in Tanks 4.0.9d (psi)	Throughput (gal/yr.)	Turnover/yr (throughput / Capacity)	Controls	Shell Color / shade	Roof Color / shade	Actual VOC Emissions from Tank 4.0.9d (lb/yr.)	Actual VOC Emissions from Tank 4.0.9d (ton/yr.)
ST-009	Asphalt*	1895	1,470,000	vertical fixed roof								None			0.00	0.00
ST-010	Asphalt*	1895	1,470,000	vertical fixed roof								None			0.00	0.00
ST-007	Oils, Reuse solvent	1956	289,800	internal floating roof								None			29.84	0.01
ST-029	Asphalt*	1956	428,400	vertical fixed roof								None			0.00	0.00
ST-062	Asphalt*	2011	49,405	vertical fixed roof								None			0.00	0.00
ST-063	Asphalt*	2011	49,405	vertical fixed roof								None			0.00	0.00
ST-064	Asphalt*	2011	49,405	vertical fixed roof								None			0.00	0.00
ST-065	Asphalt*	2011	49,405	vertical fixed roof								None			0.00	0.00
ST-021	Oils, kerosene	1975	8,820	vertical fixed roof								None			2.86	0.00
ST-060	Asphalt*	1985	2,341,920	vertical fixed roof								None			0.00	0.00
ST-061	Asphalt*	1985	5,019,042	vertical fixed roof								None			0.00	0.00
ST-090	Oil and asphalt products	'1991	30,000	vertical fixed roof								None			0.00	0.00
ST-091	Oil and asphalt products	1991	30,000	vertical fixed roof								None			0.00	0.00
ST-092	Oil and asphalt products	1991	30,000	vertical fixed roof								None			0.00	0.00
ST-093	Oil and asphalt products	1991	30,000	vertical fixed roof								None			0.00	0.00
ST-094	Oil and asphalt products	1994	30,000	vertical fixed roof								None			0.00	0.00
ST-095	Oil and asphalt products	1994	30,000	vertical fixed roof								None			0.00	0.00
ST-096	Anti-stripping Additive	1999	13,000	vertical fixed roof								None			43.28	0.02
Totals															75.99**	**0.038****
																0.038

Notes:
* - Residual Oil No.6 was used in TANKS 4.0.9d as a conservative estimate for asphalt.

** Information provided from source on each tank from TANK 4.09d program.

Appendix A: Emission Calculations
Summary of Fuel Types for Heaters (for reference only)

Company Name: Laketon Refining Corporation
Address City IN Zip: 2784 West Lukens Lake Road, Laketon, IN 46943
Permit Number: M169-33207-00006
Plt ID: 169-00006
Reviewer: Nida Habeeb
Date: May 24, 2013

Emission Unit Matrix by Fuel Type

Emission Unit		Natural Gas	No. 1 Fuel Oil	No. 2 Fuel Oil	Biofuel
SB-903	Boiler	√	√	√	√
SB-904	Boiler	√	√	√	√
HO-1	Hot Oil Heater	√	√	√	√
HO-2	Hot Oil Heater	√			
THE-930	Heater	√			

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Norman Burkett
2784 W Lukens Lake Rd
Laketon IN 46943

DATE: June 21, 2013

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

SUBJECT: Final Decision
MSOP
169-33207-00006

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
David Blackburn, Responsible Official
Debi Edwards, Agent
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 6/13/2013

Mail Code 61-53

IDEM Staff	DPABST 6/21/2013 Laketon Refining Corporation 169-33207-00006 (Final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Norman Burkett Laketon Refining Corporation 2784 W Lukens Lake Rd Laketon IN 46943 (Source CAATS) (CONFIRM DELIVERY)									
2		David Blackburn President Laketon Refining Corporation 5400 West 86th St Indianapolis IN 46943 *(RO CAATS)*									
3		Wabash County Commissioners 1 West Hill Street Wabash IN 46992 *(Local Official)*									
4		Wabash County Health Department 89 W. Hill, Memorial Hall Wabash IN 46992-3184 *(Health Department)*									
5		Ted Little Wabash County Council 1076 West 900 North North Manchester IN 46962 *(Affected Party)*									
6		Debi Edwards, 7901 West Morris St, Indianapolis, IN 46231 (Agent Information)									
7											
8											
9											
10											
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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