INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
(800) 451-6027
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TO: Interested Parties / Applicant

DATE: March 21, 2005

RE: Countrymark Cooperative, LLP / SPM 129-20112-00003

FROM: Paul Dubenetzky
Chief, Permits Branch
Office of Air Quality

Notice of Decision: Approval – Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-17-3-4 and 326 IAC 2, this permit modification is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-7-3 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office Environmental Adjudication, 100 North Senate Avenue, Government Center North, Room 1049, Indianapolis, IN 46204, **within eighteen (18) days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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

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

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

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

Enclosures
FNTV-PMOD.doc 1/10/05

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Governor

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Indianapolis, Indiana 46206-6015
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Mr. John Deaton
Countrymark Cooperative, LLP
1200 Refinery Road
Mount Vernon, IN 47620

March 21, 2005

Re: 129-20112-00003
Second Significant Permit Modification to
Part 70 Permit No.: 129-7882-00003

Dear Mr. Deaton:

Countrymark Cooperative, LLP was issued a Part 70 permit on July 21, 2003, for the operation of a petroleum refinery. An application to modify the source was received by the Office of Air Quality (OAQ) on March 15, 2004. Pursuant to the provisions of 326 IAC 2-7-12, a significant permit modification to this permit is hereby approved as described in the attached Technical Support Document.

The source modification consists of:

(a) Construction of Distillate Hydrotreater operation consisting of:
  (1) Hydrotreater Unit Reactor charge heater; and
  (2) Hydrotreater Unit Stabilizer reboiler heater.

(b) Construction of Sulfur Recovery Unit and Tail Gas Treating Unit (TGTU) consisting of:
  (1) TGTU incinerator;
  (2) TGTU Incinerator burner;
  (3) Claus Unit Startup burner; and
  (4) Sour Flare.

(c) Construction of one new storage tank to store sour water.

(d) Addition of controls on the oil/water separator unit.

(e) Construction of new wastewater drains and Modifications to existing drains.

(f) Conversion of existing Tank 46 service from unleaded gasoline to low sulfur diesel product storage and cleaning.

(g) Conversion of existing Tank 34 from light cycle oil (LCO) rundown to low sulfur distillate rundown service.

(h) Conversion of Tank 35 from FCC Cat Gasoline/Isomerate rundown to low sulfur distillate rundown service.

(i) Modification to existing FCCU Pre-heater (H-101) where this unit will no longer combust H2S from the sour Water Stripper system resulting in decrease of SO2 emissions by 33.48 tons per year.

(k) Modification to the Crude Heater C-II where this unit will be equipped with the Low NOx burner resulting in decrease of NOx by 48.44 tons per year.

(l) Increase in No. 6 fuel oil usage for the three (3) boilers (B1, B2, and B3) resulting in increase in emissions.

All other conditions of the permit shall remain unchanged and in effect

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 Adeel Yousuf, c/o OAQ, 100 North Senate Avenue, P.O. Box 6015, Indianapolis, Indiana, 46206-6015, or at 973-575-2555, extension 3252, or dial 1-800-451-6027, and ask for extension 3-6878.

Sincerely,

Original signed by
Paul Dubenetzky, Chief
Permits Branch
Office of Air Quality

Attachments
AY / EVP
cc: File – Posey County
U.S. EPA, Region V
Posey County Health Department
Air Compliance Section Inspector – Scott Anslinger
Compliance Data Section
Administrative and Development
Technical Support and Modeling - Michele Boner

Mitchell E. Daniels, Jr.
Governor

Thomas W. Easterly
Commissioner

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PART 70 OPERATING PERMIT
OFFICE OF AIR QUALITY

Countrymark Cooperative, LLP
1200 Refinery Road
Mount Vernon, Indiana 47620

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

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

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

Operation Permit No.: T129-7882-00003	
Issued by: Janet G. McCabe, Assistant Commissioner Office of Air Quality	Issuance Date: July 21, 2003 Expiration Date: July 21, 2008

Significant Permit Modification: SPM 129-20112-00003	Pages Affected: 3-5, 6, 10, 11, 19-24, 29, 37-50, 51-53, and 59-79. Pages Added: 5a, 10a, 10b, 24a, 24b, 50a-50m, 76a-76i, 79a, and 81a
Issued by: Original signed by Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: March 21, 2005

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C.16 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68.215]
C.17 Compliance Response Plan - Preparation, Implementation, Records, and Reports [326 IAC 2-7-5] [326 IAC 2-7-6]
C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

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C.19 Emission Statement [326 IAC 2-7-5(3)(C)(iii)] [326 IAC 2-7-5(7)] [326 IAC 2-7-19(c)] [326 IAC 2-6]
C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]
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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, A.3 and A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

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

The Permittee owns and operates a stationary petroleum refinery.

Responsible Official:	John T. Deaton
Source Address:	1200 Refinery Road, Mount Vernon, IN 47620
Mailing Address:	1200 Refinery Road, Mount Vernon, IN 47620
General Source Phone Number:	(812) 838-8133
SIC Code:	2911
County Location:	Posey
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Permit Program Major Source, under PSD Rules; Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

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

This stationary petroleum refinery company consists of two (2) plants:

(a) Plant 1, the refinery, is located at 1200 Refinery Road, Mount Vernon, IN 47620; and

(b) Plant 2, the river dock terminal, is located at South Mann St. and Ohio St., Mount Vernon, IN 47620.

Since the two (2) plants are located on contiguous or adjacent properties, belong to the same industrial grouping, and under common control of the same entity, they will be considered one (1) source, effective from the date of issuance of this Part 70 permit.

Separate Part 70 permits will be issued to Countrymark Cooperative, LLP with Permit No.:T129-7882-00003 and Permit No.:129-7742-00037 solely for administrative purposes.

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

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

(a) One (1) Truck loading rack, with a maximum capacity of 60,000 gallons of submerged loading of gasoline, kerosene or distillate oil per hour, installed in 1958, identified as Loading Rack, and exhausting to stack 65; controlled by the Loading Rack Flare, equipped with a 0.09 million British Thermal Units per hour (mmBtu/hr) natural gas fired pilot and designed to handle 160 actual cubic feet per minute (acfm) of hydrocarbon vapors, installed in 1998, and exhausting to stack 1D;

(b) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no sour water stripper overhead off-gas combustion), installed in 1945 and exhausting to stack 9;

(c) one (1) FCCU regenerator, identified as V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10;

58	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1980	102;
159	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	103;
160	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	104;
161	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	105;
162	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	106;
163	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1983	107;
164	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1983	108;
165	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	109;
166	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	110;
167	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	111;
168	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	112;
169	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1989	113;
125	fixed roof cone tank	157,000	6,000	hydrocarbon with vapor pressure of No.2 fuel oil or less	2005	015;

(e) one (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 and exhausting to stack 118;

(f) one (1) Crude heater equipped with a Low-NOx burner, identified as C-II with a maximum heat input rate of 131 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1955 and exhausting to stack 1;

(g) one (1) Unifiner heater, identified as H-H5 with a maximum heat input rate of 20 mmBtu/hr, combusting refinery fuel gas, installed in 1959 and exhausting to stack 2;

(h) one (1) Cycle oil heater, identified as H-H2 with a maximum heat input rate of 10 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 3;

(i) one (1) Naphtha splitter heater, identified as H-H3 with a maximum heat input rate of 12.2 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 4;

(j) one (1) Vacuum heater, identified as V-IV with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950 and exhausting to stack 5;

(k) one (1) Old Platformer heater, identified as P-H1 with a maximum heat input rate of 29 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 6;

(l) one (1) Alkylation unit heater, identified as A-H1 with a maximum heat input rate of 13.2 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1966 and exhausting to stack 7;

(m) one (1) Auxiliary crude heater, identified as C-I with a maximum heat input rate of 10.1 mmBtu/hr, combusting refinery fuel gas, installed in 1966 and exhausting to stack 11;

(n) one (1) Platformer stabilizer reb, identified as P-H2 with a maximum heat input rate of 5.92 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 12;

(o) one (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;
(p) one (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;
(q) one (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;
(r) one (1) Vacuum heater husky, identified as VIII with a maximum heat input rate of 6.27 mmBtu/hr, combusting refinery fuel gas No. 6 residual fuel oil,, installed in 1963 and exhausting to stack 64;
(s) one (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74;
(t) two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071;
(u) one (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;
(v) pipeline Valves - Gas, identified as 090;
(w) pipeline Valves - Light Liquid, identified as 091;
(x) pipeline Valves - Heavy Liquid, identified as 092;
(y) pipeline Valves - Hydrogen, identified as 093;
(z) open Ended Valves, identified as 094;
(aa) flanges, identified as 095;
(bb) pump Seals Light Liquid, identified as 096;
(cc) pump Seals Heavy Liquid, identified as 097;
(dd) compressor Seals - Gas, identified as 098;
(ee) compressor Seals - Heavy Liquid, identified as 099;
(ff) drains, identified as 100;
(gg) vessel Relief Valves, identified as 101;
(hh) cooling Towers, identified as 119; and
(ii) process units made up of vessels, piping, exchangers, identified as PENEX.
(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (to be constructed in 2005).
(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 (to be constructed in 2005).
(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:
  (1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).
  (2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.
  (3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).
  (4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).
(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of:
  (1) pipeline Valves - Gas, identified as 090;
  (2) pipeline Valves - Light Liquid, identified as 091;
  (3) pipeline Valves - Heavy Liquid, identified as 092;
  (4) pipeline Valves - Hydrogen, identified as 093;
  (5) open Ended Valves, identified as 094;

(6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(7) flanges, identified as 095;
(8) pump Seals Light Liquid, identified as 096;
(9) pump Seals Heavy Liquid, identified as 097;
(10) compressor Seals - Gas, identified as 098;
(11) compressor Seals - Heavy Liquid, identified as 099;
(12) drains, identified as 100;
(13) vessel Relief Valves, identified as 101; and
(14) cooling Towers, identified as 119.

A.4 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)][326 IAC 2-7-5(15)]

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

(a) Metal and related material cutting, fabricating and preparation. [326 IAC 6-3]
(b) Sand blasting or mechanical stripping on tanks and other equipment. [326 IAC 6-3]
(c) Painting on tanks and other equipment. [326 IAC 6-3]
(c) Welding/Cutting of metal for vessel, pipeline and equipment maintenance. [326 IAC 6-3]

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

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

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

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

SECTION B GENERAL CONDITIONS

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

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

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

(a) This permit, T129-7882-00003, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

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

B.3 Enforceability [326 IAC 2-7-7]

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

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

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

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

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

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

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

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

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ, may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The submittal by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34). 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 Compliance with Permit Conditions [326 IAC 2-7-5(6)(A)] [326 IAC 2-7-5(6)(B)]

(a) The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for:

(1) Enforcement action;

(2) Permit termination, revocation and reissuance, or modification; or

(3) Denial of a permit renewal application.

(b) Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act.

(c) It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(d) An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

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

(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form, with each submittal requiring certification.

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

B.10 Annual Compliance Certification [326 IAC 2-7-6(5)]

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

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

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

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

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, 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 Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

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

(b) The Permittee shall implement the PMPs, including any required record keeping, as necessary to ensure that failure to implement a PMP does not cause or contribute to an exceedance of any limitation on emissions or potential to emit.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ, 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 or potential to emit. The PMP does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.12 Emergency Provisions [326 IAC 2-7-16]

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

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

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

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

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

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or
Telephone Number: 317-233-5674 (ask for Compliance Section)
Facsimile Number: 317-233-5967

Telephone Number: 812-436-2570
Facsimile Number: 812-436-2572

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

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) IDEM, OAQ, may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4-(c)(9) be revised in response to an emergency.

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

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

(h) Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report.

B.13 Permit Shield [326 IAC 2-7-15] [326 IAC 2-7-20] [326 IAC 2-7-12]

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

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

(b) In addition to the nonapplicability determinations set forth in Sections D of this permit, the IDEM, OAQ has made the following determination regarding this source:

Federal Rule Applicability (Plant 1)

(1) Three (3) boilers identified as Boiler Nos. 1, 2 and 3, constructed in 1957, 1970 and 1957, and rated at 52.0, 65.0 and 52.0 mmBtu per hour, respectively are not subject to New Source Performance Standard, 326 IAC 12, (40 CFR 60.40c, Subpart Dc) because both were constructed prior to the rule applicability date of June 9, 1989.

(2) (i) The one (1) FCCU regenerator, with a maximum heat input rate of 13.2 mmBtu/hr of process gas and maximum throughput rate of 380 barrels of fresh crude feed per hour, identified as V 5, installed in 1950, and refinery fuel gas combustion units (FCCU preheater, Main refinery flare, Crude heater, Unifier heater, Alkylation unit heat, Auxiliary crude heater, Platformer stabilizer reb, Boilers Nos. 1, 2 and 3, Vacuum heater husky) are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60.100, Subpart J Standards of Performance for Petroleum Refineries), because all units commenced construction or modification before the rule applicability date of June 11, 1973.

(ii) Any Fluid catalytic cracking unit catalyst regenerator under 40 CFR 60.100 paragraph (b) which commences construction or modification on or before January 17, 1984, is exempted from 40 CFR 60.104(b).

(iii) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction or modification on or before January 17, 1984, is exempt from this subpart.

(iv) The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from 40 CFR 60.104 paragraph (a)(1).

(3) Storage tanks identified as Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11A, 11B, 15, 17, 18, 19, 21, 22, 25, 26, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 49, 48 and 50 are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Parts 60.110, 110a 115a or 110b 117b, Subparts K, Ka and Kb), because these tanks were all constructed between 1940 and 1958, prior to the earliest applicability date of June 11, 1973 for Subpart K, Ka or Kb.

(4) The following are exempt from the requirements of 40 CFR 60.113:
(A) Each Permittee of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).
(B) Each Permittee of each affected facility equipped with a vapor recovery and return or disposal system in accordance with the requirements of 40 CFR 60.112.

(5) Storage tanks identified as Nos. 55, 56, 58, 163 and 164 are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.110a, Subpart Ka), because each tank, constructed between 1980 and 1983, has a storage capacity less than 40, 000 gallons.

(6) The truck loading rack, identified as Loading Rack, and the Loading Rack Flare, identified as 065 are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.500, Subpart XX) "Standards of Performance for Bulk Gasoline Terminals" because the loading rack was constructed or modified prior to the rule applicability date of December 17, 1980.

(7) This source is not subject to the requirements of the National Emission Standards for Hazardous Air Pollutants 326 IAC 20.17, (40 CFR 63.560, Subpart Y) because there are no marine tank vessel loading operations at plant 1.

(8) Compressors in hydrogen service are exempt from the requirements of 40 CFR 60.592 if a Permittee demonstrates that a compressor is in hydrogen service.

(9) Any existing reciprocating compressor that becomes an affected facility under provisions of 40 CFR 60.14 or 40 CFR 60.15 is exempt from 40 CFR 60.482(a), (b), (c), (d), (e), and (h).

(10) Storage vessels that are to comply with 40 CFR 60.112b(a)(2) of Subpart Kb are exempt from the secondary seal requirements of 40 CFR 60.112b(a)(2)(I)(B) during the gap measurements for the primary seal required by 40 CFR 60.113b(b) of Subpart Kb.

State Rule Applicability Entire Source (Plant 1)

(11) 326 IAC 2 2 (Prevention of Significant Deterioration): This rule applies to sources commencing construction after August 7, 1977. This source was constructed prior to the applicability date but potential emissions after control were greater than 100 tons per year as of August 7, 1977 as stated above. Therefore, the source was a major PSD source for purposes of determining applicability of this rule to future modifications. Each of the modifications after August 7, 1977, had potential to emit VOC of less than 40 tons per year. Therefore, this rule does not apply.

State Rule Applicability Individual Facilities (Plant 1)

(12) 326 IAC 8 1 6 (New Facilities; General Reduction Requirements): This rule applies to facilities located in any county constructed after January 1, 1980, which are not otherwise regulated by any other provisions of 326 IAC 8, and have potential emissions of 25 tons/yr or greater. The Truck loading rack was constructed in 1958, before the rule applicability date of January 1, 1980.

(13) 326 IAC 8 4 3 (Petroleum Liquid Storage Facilities): All storage tanks at the source are not subject to this rule, except for Tank Nos. 18 and 24.

(14) 326 IAC 8 4 4 (Bulk Gasoline Terminals): The Truck Loading Rack, identified as Loading Rack is not subject to this rule because it was constructed in 1958 before the rule applicability date of January 1, 1980.

(15) 326 IAC 8 4 5 (Bulk Gasoline Plants): This source is not subject to the requirements of 326 IAC 8-4-5 (Bulk Gasoline Plants), because it is not located in any of the listed counties.

(16) 326 IAC 8 4 6 (Gasoline Dispensing Facilities): The Truck Loading Rack is not subject to this rule because the Truck Loading Rack does not dispense gasoline into motor vehicle fuel tanks or portable containers, is not a gasoline dispensing facility, and is not located in any of the listed counties.

(17) 326 IAC 8 4 7 (Gasoline Transports): Plant 1 is not subject to the requirements of 326 IAC 8-4-7 (Gasoline Transports), because it is not an owner or operator of a gasoline transport, and is not located in any of the listed counties.

(18) 326 IAC 8 4 9 (Leaks from Transports and Vapor Collection Systems; Records): Plant 1 is not subject to this rule because it is not subject to the requirements of 326 IAC 8-4-4 through 326 IAC 8-4-6 and also not subject to the requirements of 326 IAC 8-4-9 (Leaks from Transports and Vapor Collection Systems, Records).

(19) 326 IAC 8 7 (Specific VOC Reduction Requirements for Lake, Porter, Clark and Floyd Counties): Plant 1 is not subject to the requirements of 326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark and Floyd Counties), because the source is not located in one of the listed counties.

(20) 326 IAC 8 9 (Volatile Organic Liquid Storage Vessels): Plant 1 is not subject to the requirements of 326 IAC 8-9 (Volatile Organic Liquid Storage Vessels) because this source is not located in one of the listed counties.

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

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

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

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

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

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

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

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

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

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

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

(a) All terms and conditions of permits established prior to T129-7882-00003 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

(b) Provided that all terms and conditions are accurately reflected in this combined permit, all previous registrations and permits are superseded by this combined new source review and part 70 operating permit.

B.15 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]

(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provisions), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. A deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report.

The Quarterly Deviation and Compliance Monitoring Report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.16 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)] [326 IAC 2-7-8(a)] [326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ, determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ, to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ, at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ, may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.17 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] [326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

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

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

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

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

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

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

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

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

(d) No permit amendment or modification is required for the addition, operation or removal of a nonroad engine, as defined in 40 CFR 89.2.

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

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

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

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

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

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

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

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

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

and

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

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

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

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

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;

(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ, or U.S. EPA is required.

B.21 Source Modification Requirement [326 IAC 2-7-10.5] [326 IAC 2-3-2]

(a) A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2 and 326 IAC 2-7-10.5.

(b) Any modification at an existing major source is governed by the requirements of 326 IAC 2-3-2.

B.22 Inspection and Entry [326 IAC 2-7-6] [IC 13-14-2-2] [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 Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

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

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

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

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

B.23 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

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

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

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

The application which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.24 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

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

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

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

B.25 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314]

Notwithstanding the conditions of this permit that state specific methods that may be used to demonstrate compliance with, or a violation of, applicable requirements, any person (including the Permittee) may also use other credible evidence to demonstrate compliance with, or a violation of, any term or condition of this permit.

B.26 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.

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

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

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

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant which is used only for purposes of Section 19 of this rule") from the source, for purposes of Part 70 fee assessment.

(b) The annual emission statement covers the twelve (12) consecutive month time period starting January 1 and ending December 31. The annual emission statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

The emission statement does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The annual emission statement 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.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(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, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

C.21 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11]

(a) The source shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

SECTION D.2 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(a) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74.

(b) One (1) FCCU regenerator, identified as V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10.

(c) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (to be constructed in 2005).

(d) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 (to be constructed in 2005).

(e) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:

(1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).

(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).

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

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

D.2.1 General Provisions Relating to HAPs [326 IAC 12-1-1] [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to one (1) CCR platformer described in this section except when otherwise specified in 40 CFR Part 60, Subpart J.

D.2.2 General Provisions Relating to HAPs [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

(a) The provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facilities described in this section except when otherwise specified in 40 CFR Part 63, Subpart UUU.

(b) The provisions of 40 CFR 63 Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the affected sources, as designated by 40 CFR 63.7506(b). The Permittee must comply with these requirements on and after the effective date of 40 CFR 63, Subpart DDDDD.

D.2.3 Petroleum Refineries NSPS [326 IAC 12-1-1] [40 CFR 60, Subpart J]

The CCR Platformer Heater, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2), and Sour Flare (124-4) are subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.100, Subpart J) "Standards of Performance for Petroleum Refineries," because the refinery fuel gas combustion devices commenced construction or modification after June 11, 1973.

D.2.4 Petroleum Refineries NESHAP [326 IAC 20-1-1] [40 CFR 63, Subpart UUU]

Pursuant to 40 CFR 63.1560, the one (1) existing catalytic cracking unit and one (1) catalytic reforming unit, known as FCCU regenerator and CCR Platformer Unit, respectively, and the new Sulfur Recovery Unit and TGTU, identified as 124, and the bypass lines serving these units are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP), 326 IAC 20-14, (40 CFR 63, Subpart UUU), with a compliance date of April 11, 2005 except as specified in 40 CFR 63.1563 paragraph (c).

The Permittee shall submit a notification of compliance options chosen no later than 180 days prior to the initial compliance date, which is April 11, 2005. The notification of compliance options chosen shall contain all the information required in 40 CFR 63.1570 through 63.1573 that is appropriate for the facility.

D.2.5 Standards for Sulfur Oxides Emissions from Fuel Gas Combustion Devices [40 CFR 60.104]

Pursuant to 40 CFR 60.104, the following shall apply to the CCR Platformer Heater, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2):

The Permittee that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

No Permittee subject to the provisions of this subpart shall burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

D.2.6 NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-1-1] [40 CFR Part 63, Subpart DDDDD]

Pursuant to 40 CFR 63.7490, the provisions of 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, apply to the Hydrotreater Unit Reactor Charge and Stabilizer Reboiler Heaters, identified as 122 and 123, respectively, because these are new facilities being constructed after January 13, 2003 and meet the criteria in the definition in 40 CFR 63.7575 for the large gaseous fuel subcategory.

D.2.7 Standards for Metal HAP Emissions from Catalytic Cracking Units [40 CFR 63.1564]

(a) Pursuant to 40 CFR 63.1564, the following emission limitations and work practice standards shall apply to the FCCU regenerator:
   (1) The Permittee shall comply with each applicable emission limitation in Table 1 of this subpart. This catalytic cracking unit is not subject to the NSPS for PM, therefore, the Permittee must choose a compliance option from the four options listed in 40 CFR 63.1564 paragraphs (a)(1)(i) through (iv).
   (2) The Permittee shall comply with each applicable operating limit in Table 2 of this subpart.
   (3) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in 40 CFR 63.1574(f) and operate at all times according to the procedures in the plan.
   (4) The applicable emission limitations and operating limits for metal HAP emissions from catalytic cracking units required in 40 CFR 63.1564 paragraphs (a)(1) and (2) do not apply during periods of planned maintenance preapproved by IDEM, OAQ according to the requirements in 40 CFR 63.1575(j).

(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:
   (1) Demonstrate applicable continuous compliance with each applicable emission limitation in Tables 1 and 2 of this subpart according to the methods specified in Tables 6 and 7 of this subpart.
   (2) Demonstrate continuous compliance with the work practice standard in 40 CFR 63.1564 paragraph (a)(3) by maintaining records to document conformance with the procedures in the operation, maintenance, and monitoring plan.
   (3) If the Permittee uses a continuous opacity monitoring system and elects to comply with Option 3 listed in 40 CFR 63.1564 paragraph (a)(1)(iii), determine continuous compliance with your site-specific Ni operating limit by using Equation 11 in 40 CFR 63.1564.
   (4) If the Permittee uses a continuous opacity monitoring system and elects to comply with Option 4 listed in 40 CFR 63.1564 paragraph (a)(1)(iv), determine continuous compliance with your site-specific Ni operating limit by using Equation 12 in 40 CFR 63.1564.

D.2.8 Standards for Organic HAP Emissions from Catalytic Cracking Units [40 CFR 63.1565]

(a) Pursuant to 40 CFR 63.1565, the following emission limitations and work practice standards shall apply to the FCCU regenerator:
   (1) The Permittee shall comply with each applicable emission limitation in Table 8 of this subpart. This catalytic cracking unit is not subject to the NSPS for CO, therefore, the Permittee must choose a compliance option from the two options listed in 40 CFR 63.1564 paragraphs (a)(1)(i) through (ii).
   (2) The Permittee shall comply with each applicable site-specific operating limit in Table 9 of this subpart.
   (3) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in 40 CFR 63.1574(f) and operate at all times according to the procedures in the plan.
   (4) The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in 40 CFR 63.1565 paragraphs (a)(1) and (2) do not apply during periods of planned maintenance preapproved by IDEM, OAQ according to the requirements in 40 CFR 63.1575(j).

(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:
   (1) Demonstrate applicable continuous compliance with each applicable emission limitation in Tables 8 and 9 of this subpart according to the methods specified in Tables 13 and 14 of this subpart.
   (2) Demonstrate continuous compliance with the work practice standard in 40 CFR 63.1565 paragraph (a)(3) by complying with the procedures in the operation, maintenance, and monitoring plan.

D.2.9 Standards for Organic HAP Emissions from Catalytic Reforming Units [40 CFR 63.1566]

(a) Pursuant to 40 CFR 63.1566, the following emission limitations and work practice standards shall apply to the CCR Platformer unit:
   (1) The Permittee shall comply with each applicable emission limitation in Table 15 of this subpart. The Permittee must choose from the two options listed in 40 CFR 63.1566 paragraphs (a)(1)(i) through (ii).
   (2) The Permittee shall comply with each applicable site-specific operating limit in Table 16 of this subpart.
   (3) The emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents that occur during depressuring and purging operations. These process vents include those used during unit depressurization, purging, coke burn, catalyst rejuvenation, and reduction or activation purge.
   (4) The emission limitations in Tables 15 and 16 of this subpart do not apply to emissions from process vents during depressuring and purging operations when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less.
   (5) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in 40 CFR 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:
   (1) Demonstrate applicable continuous compliance with each applicable emission limitation in Tables 15 and 16 of this subpart according to the methods specified in Tables 20 and 21 of this subpart.
   (2) Demonstrate continuous compliance with the work practice standards in 40 CFR 63.1566 paragraph (a)(3) by complying with the procedures in the operation, maintenance, and monitoring plan.

D.2.10 Standards for Inorganic HAP Emissions from Catalytic Reforming Units [40 CFR 63.1567]

(a) Pursuant to 40 CFR 63.1567, the following emission limitations and work practice standards shall apply to the CCR Platformer:
  (1) The Permitte shall comply with each applicable emission limitation in Table 22 of this subpart. These emission limitations apply during coke burn-off and catalyst rejuvenation. The Permittee must choose a compliance option from the two options listed in 40 CFR 63.1567 paragraphs (a)(1)(i) through (ii).
  (2) The Permittee shall comply with each applicable site-specific operating limit in Table 23 of this subpart. These operating limits apply during coke burn-off and catalyst rejuvenation.
  (3) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in 40 CFR 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate continuous compliance with the emission limitations and work practice standard, the Permittee shall:
  (1) Demonstrate applicable continuous compliance with each emission limitation in Tables 22 and 23 of this subpart according to the methods specified in Tables 27 and 28 of this subpart.
  (2) Demonstrate continuous compliance with the work practice standard in 40 CFR 63.1567 paragraph (a)(3) by maintaining records to document conformance with the procedures in the operation, maintenance and monitoring plan.

D.2.11 Standards for HAP Emissions from Sulfur Recovery Units [40 CFR 63.1568] [326 IAC 20-50-1]

(a) Pursuant to 40 CFR 63.1568, the following emission limitations and work practice standards shall apply to the Sulfur Recovery Unit and TGTU:
  (1) The Permittee shall comply with each applicable emission limitation in Table 29 of this subpart. The Sulfur Recovery Unit and TGTU are not subject to the NSPS for SO_2, therefore, the Permittee must choose from the options in paragraphs (a)(1)(i) through (ii) of 40 CFR 63.1568:
    (i) The Permittee can elect to meet the NSPS requirements (Option 1); or
    (ii) The Permittee can elect to meet the total reduced sulfur (TRS) emission limitation (Option 2).
  (2) The Permittee shall comply with each operating limit in Table 30 of this subpart.
  (3) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:
  (1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies according to the methods specified in Tables 34 and 35 of this subpart.
  (2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this 40 CFR 633.1568 by complying with the procedures in the operation, maintenance, and monitoring plan.

D.2.12 Standards for HAP Emissions from Bypass Lines [40 CFR 63.1569] [326 IAC 20-50-1]

(a) Pursuant to 40 CFR 63.1569, the following emission limitations and work practice standards shall apply to the bypass lines:
  (1) The Permittee shall meet each work practice standard in Table 36 of this subpart. The Permittee can choose from the four options in paragraphs (a)(1)(i) through (iv) of 40 CFR 63.1569:
    (i) The Permittee can elect to install an automated system (Option 1);
    (ii) The Permittee can elect to use a manual lock system (Option 2);
    (iii) The Permittee can elect to seal the line (Option 3); or
    (iv) The Permittee can elect to vent to a control device (Option 4).
  (2) As provided in § 63.6(g), the EPA, may choose to grant permission to use an alternative to the work practice standard in paragraph (a)(1) of 40 CFR 63.1569.
  (3) The Permittee must prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:
  (1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies according to the requirements in Table 39 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of 40 CFR 63.1569 by complying with the procedures in the operation, maintenance, and monitoring plan.

D.2.13 Emission Limits and Work Practice Standards [326 IAC 20-1-1] [40 CFR Part 63, Subpart DDDDD]

Pursuant to 40 CFR 63.7500, the Permittee shall comply with the following requirements.

(a) The Permitte shall meet each emission limit and work practice standard in Table 1 of this subpart that applies to the boiler or process heater, except as provided under §63.7507.

(b) The Permittee must meet each operating limit in Tables 2 through 4 to this subpart that applies to the boiler or process heater. If the Permittee uses a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or wishes to establish and monitor an alternative operating limit and alternative monitoring parameters, the Permittee must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under §63.8(f).

As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

D.2.14 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the CCR platformer heater, identified as 300 - H1, H2, H3, FCCU regenerator, identified as V-5, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2)and any control devices.

Compliance Determination Requirements [326 IAC 2-1.1-11] [326 IAC 2-7-6(1)]

D.2.15 Performance Testing [40 CFR 60.106]

During the period between 60 and 180 days following the effective date of becoming subject to the rule 40 CFR 60.104, in order to demonstrate compliance with Condition D.2.5, the Permittee shall perform H_2S testing for the CCR Platformer Heater, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2) utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C- Performance Testing.

Pursuant to 40 CFR 60.106, the following test methods and procedures shall apply to the refinery fuel gas combustion device:

(a) In conducting the performance tests required in 60.8, the Permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in 60.8(b).

(b) The Permittee shall determine compliance with the H_2S standard in 60.104(a)(1) as follows: Method 11 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

D.2.16 Initial Compliance Demonstration [40 CFR 63.1564 - 1569] [326 IAC 20-50-1]

(a) The Permittee shall demostrate initial compliance with the emission limitations and work practice standards for Metal HAP Emissions from Catalytic Cracking unit (FCCU) by:
- (1) Installing, operating, and maintaining a continuous monitoring system(s) according to the requirements in 40 CFR 63.1572 and Table 3 of this subpart.
- (2) Conducting a performance test for each catalytic cracking unit not subject to the NSPS for PM according to the requirements in 40 CFR 63.1571 and under the conditions specified in Table 4 of this subpart.
- (3) Establishing each applicable site-specific operating limit in Table 2 of this subpart according to the procedures in Table 4 of this subpart.
- (4) Using the procedures in 40 CFR 63.1564 paragraphs (b)(4)(i) through (iv) to determine initial compliance with the applicable emission limitations.

(b) The Permittee shall demostrate initial compliance with the emission limitations and work practice standards for Organic HAP Emissions from Catalytic Cracking unit (FCCU) by:
- (1) Installing, operating, and maintaining a continuous monitoring system according to the requirements in 40 CFR 63.1572 and Table 10 of this subpart. Except:
  - (i) Whether or not the catalytic cracking unit is subject to the NSPS for CO in 40 CFR 60.103, the Permittee does not have to install and operate a continuous emission monitoring system if the Permittee shows that CO emissions from the vent average less than 50 parts per million (ppm), dry basis. The Permittee shall get an exemption from IDEM, OAQ, based on the Permittee's written request. To show that the emissions average is less than 50 ppm (dry basis), the Permittee shall continuously monitor CO emissions for 30 days using a CO continuous emission monitoring system that meets the requirements in 40 CFR 63.1572.
  - (ii) If the catalytic cracking unit is not subject to the NSPS for CO, then the Permittee does not have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if the Permittee vents emissions to a boiler (including a "CO boiler") or process heater that has a design heat input capacity of at least 44 megawatts (MW).
  - (iii) If the catalytic cracking unit is not subject to the NSPS for CO, then the Permittee does not have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if the Permittee vents emissions to a boiler or process heater in which all vent streams are introduced into the flame zone.
- (2) Conducting each performance test for a catalytic cracking unit not subject to the NSPS for CO according to the requirements in 40 CFR 63.1571 and under the conditions specified in Table 11 of this subpart.
- (3) Establishing each applicable site-specific operating limit in Table 9 of this subpart according to the procedures in Table 11 of this subpart.
- (4) Demonstrating initial compliance with each applicable emission limitation according to Table 12 of this subpart.
- (5) Demonstrating initial compliance with the work practice standard in 40 CFR 63.1565 paragraph (a)(3) by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the Notification of Compliance Status according to 40 CFR 63.1574.
- (6) Submitting the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.1574.

(c) The Permittee shall demostrate initial compliance with the emission limitations and work practice standards for Organic HAP Emissions from Catalytic Reforming unit (CCR) by:
- (1) Installing, operating, and maintaining a continuous monitoring system(s) according to the requirements in 40 CFR 63.1572 and Table 17 of this subpart.
- (2) Conducting each performance test for a catalytic reforming unit according to the requirements in 40 CFR 63.1571 and under the conditions specified in Table 18 of this subpart.
- (3) Establishing each applicable site-specific operating limit in Table 16 of this subpart according to the procedures in Table 18 of this subpart.
- (4) Using the procedures in 40 CFR 60.1566 paragraph (b)(4)(i) or (ii) to determine initial compliance with the emission limitations.

(5) If the Permittee elects the 20 parts per million by volume (ppmv) concentration limit, correct the measured TOC concentration for oxygen (O2) content in the gas stream using Equation 4 in section 40 CFR 63.1566(b)(5).

(6) The Permittee is not required to do a TOC performance test if:

(i) elects to vent emissions to a flare as provided in 40 CFR 63.1566 paragraph (a)(1)(i) (Option 1); or

(ii) elects the TOC percent reduction or concentration limit in 40 CFR 63.1566 paragraph (a)(1)(ii) (Option 2), and uses a boiler or process heater with a design heat input capacity of 44 MW or greater or a boiler or process heater in which all vent streams are introduced into the flame zone.

(7) Demonstrating initial compliance with each applicable emission limitation according to Table 19 of this subpart.

(8) Demonstrating initial compliance with the work practice standard in 40 CFR 63.1566 paragraph (a)(5) by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the Notification of Compliance Status.

(9) Submitting the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.1574.

(d) The Permittee shall demostrate initial compliance with the emission limitations and work practice standards for Inorganic HAP Emissions from Catalytic Reforming unit (CCR) by:

(1) Installing, operating, and maintaining a continuous monitoring system(s) according to the requirements in 40 CFR 63.1572 and Table 24 of this subpart.

(2) Conducting each performance test for a catalytic reforming unit according to the requirements in 40 CFR 63.1571 and the conditions specified in Table 25 of this subpart.

(3) Establishing each applicable site-specific operating limit in Table 23 of this subpart according to the procedures in Table 25 of this subpart.

(4) Demonstrating initial compliance with each applicable emission limitation according to Table 26 of this subpart.

(5) Demonstrating initial compliance with the work practice standard in 40 CFR 63.1567 paragraph (a)(3) by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the Notification of Compliance Status.

(6) Submitting the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.1574.

(e) To demonstrate initial compliance with the emission limitations and work practice standards for Sulfur Recovery Units, the Permittee shall:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 31 of this subpart.

(2) Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in § 63.1571 and under the conditions specified in Table 32 of this subpart.

(3) Establish each site-specific operating limit in Table 30 of this subpart that applies according to the procedures in Table 32 of this subpart.

(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of 40 CFR 63.1568.

(5) Demonstrate initial compliance with each emission limitation that applies according to Table 33 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of 40 CFR 63.1568 by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of notification of compliance status.

(7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(f) To demonstrate initial compliance with the emission limitations and work practice standards for Bypass Lines, the Permittee shall:

(1) If the Permittee elects the option in paragraph (a)(1)(i) of 40 CFR 63.1569, conduct each performance test for a bypass line according to the requirements in § 63.1571 and under the conditions specified in Table 37 of this subpart.

(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies according to Table 38 of this subpart.
(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this 40 CFR 63.1569 by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the notification of compliance status.
(4) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

D.2.17 Performance Testing [40 CFR 63.1571]

(a) The Permittee shall conduct performance tests and report the results by no later than 150 days after the compliance date specified for the source in 40 CFR 63.1563 and according to the provisions in 40 CFR 63.7(a)(2). If the Permittee is required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, the Permittee may do them at the first regeneration cycle after the source's compliance date and report the results in a follow-up Notification of Compliance Status report due no later than 150 days after the test.

(1) For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, the Permittee shall conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for the source in 40 CFR 63.1563.
(2) For each emission limitation where the averaging period is 30 days, the 30-day period for demonstrating initial compliance begins at 12:00 a.m. on the compliance date that is specified for the source in 40 CFR 63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for the source in 40 CFR 63.1563.

(b) The Permittee shall:

(1) Conduct each performance test according to the requirements in 40 CFR 63.7(e)(1).
(2) Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in 40 CFR 63.7(e)(3). Each test run must last at least 1 hour.
(3) Conduct each performance evaluation according to the requirements in 40 CFR 63.8(e).
(4) Not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 40 CFR 63.7(e)(1).
(5) Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5, or 8 of 40 CFR 63.1564, and determining the arithmetic average of the calculated emission rates.

(c) The Permittee may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If the Permittee uses an engineering assessment, the Permittee shall document all data, assumptions, and procedures to the satisfaction of IDEM, OAQ. An engineering assessment may include the approaches listed in 40 CFR 63.1571 paragraphs (c)(1) through (c)(4). Other engineering assessments may be used but are subject to review and approval by IDEM, OAQ.
(1) The Permittee may use previous test results provided the tests are representative of current operating practices at the process unit, and provided EPA methods or approved alternatives were used;
(2) the Permittee may use bench-scale or pilot-scale test data representative of the process under representative operating conditions;
(3) the Permittee may use maximum flow rate, TOC emission rate, organic HAP emission rate, or organic HAP or TOC concentration specified or implied within a permit limit applicable to the process vent; or
(4) the Permittee may use design analysis based on engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:
(i) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;
(ii) Calculation of hourly average maximum flow rate based on physical equipment design such as pump or blower capacities; and

(iii) Calculation of TOC concentrations based on saturation conditions.

(d) If the Permittee does a performance test to demonstrate compliance, then the Permittee shall base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. The Permittee may adjust the values measured during the performance test according to the criteria in paragraphs (d)(1) through (3) of 40 CFR 63.1571

D.2.18 Testing, Fuel Analyses, and Initial Compliance Requirements [40 CFR 63.7510] [40 CFR 63.7515] [40 CFR 63.7520]

Pursuant to 40 CFR 63.7510, the Permittee shall comply with the following initial compliance requirements:

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, the initial compliance requirements include conducting performance tests according to §63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in the boiler or process heater according to §63.7521 and Table 6 of this subpart, establishing operating limits according to §63.7530 and Table 7 of this subpart, and conducting CMS performance evaluations according to §63.7525.

(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, the initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in the boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart.

(c) For affected sources that have an applicable work practice standard, the initial compliance requirements depend on the subcategory and rated capacity of the boiler or process heater. If the boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, then the initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If the boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, then the initial compliance demonstration is conducting a performance evaluation of the continuous emission monitoring system for carbon monoxide according to §63.7525(a).

(d) For existing affected sources, the Permittee must demonstrate initial compliance no later than 180 days after the compliance date that is specified for the source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart.

(e) If the new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and September 13, 2004, then the Permittee must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after September 13, 2004 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(f) If the new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and September 13, 2004, and the Permittee choses to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, the Permittee must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after September 13, 2004 or within 3 years after startup of the affected source, whichever is later.

(g) If the new or reconstructed affected source commences construction or reconstruction after September 13, 2004, then the Permittee must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

Pursuant to 40 CFR 63.7510, the Permittee shall comply with the following performance test requirements:

(a) The Permittee must conduct all applicable performance tests according to §63.7520 on an annual basis, unless the permittee follows the requirements listed in paragraphs (b) through (d) of 40 CFR 63.7510. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless the Permittee follows the requirements listed in paragraphs (b) through (d) of 40 CFR 63.7510.

(b) The permittee can conduct performance tests less often for a given pollutant if the performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that the Permittee complies with the emission limit. In this case, the Permittee does not have to conduct a performance test for that pollutant for the next 2 years. The Permittee must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If the boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, the Permittee may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, the Permittee must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If the Permittee has an applicable work practice standard for carbon monoxide and the boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, the Permittee must conduct annual performance tests for carbon monoxide according to §63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

(f) The Permittee must conduct a fuel analysis according to §63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If the Permittee burns a new type of fuel, then the Permittee must conduct a fuel analysis before burning the new type of fuel in the boiler or process heater. The Permittee must still meet all applicable continuous compliance requirements in §63.7540.

(g) The Permittee must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for the affected source have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550.

Pursuant to 40 CFR 63.7520, the Permittee is subject to the following performance test procedures:

(a) The Permittee must conduct all performance tests according to §63.7(c), (d), (f), and (h). The Permittee must also develop a site-specific test plan according to the requirements in §63.7(c) if the Permittee elects to demonstrate compliance through performance testing.

(b) The Permittee must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(d) The Permittee must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. The Permittee must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and the Permittee must demonstrate initial compliance and establish the operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.

(e) The Permittee may not conduct performance tests during periods of startup, shutdown, or malfunction.

(f) The Permittee must conduct three separate test runs for each performance test required in 40 CFR 63.7520, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(g) To determine compliance with the emission limits, the Permittee must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

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

D.2.19 Continuous Monitoring [40 CFR 60.105]

(a) Pursuant to 40 CFR 60.105, the CCR Platformer Heater, identified as 300 - H1, H2, H3, has applicable compliance monitoring conditions as specified below:

Pursuant to a September 16, 1984 letter from the USEPA, an Alternative monitoring plan was approved with the following conditions.

(1) The fuel gas must be sampled every 8 hours during the unit's operation at the representative location and analyze the H_2S concentration using three Draeger tubes with a span of 0-15 parts per million (ppm) for each sampling effort.

(2) Average the Draeger tube readings for each sampling event.

(3) If the results H_2S concentrations exceed 10 ppm, within 1 hour begin performing H_2S sampling and analysis every hour using three Draeger tubes with a span of 0-200 ppm.

(4) When 3 consecutive hours of sampling with the 200 ppm Draeger tubes indicate that the H_2S concentration is below 10 ppm, revert to using the 15 ppm Draeger tubes every 8 hours.

(5) If the H_2S ever exceeds 80 ppm, install and certify an H_2S CEM within 180 days and, in the meantime, follow this approved alternative monitoring method.

(6) Submit quarterly summary reports indicating all instances when the H_2S concentration exceeded 10 ppm, the actual H_2S concentration, and times when the unit was not operational.

(7) Maintain records of the Draeger tube results used to prepare the quarterly reports on file for at least 2 years.

(b) Pursuant to 40 CFR 60.105, the Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2) have applicable compliance monitoring conditions as specified below:

(1) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(a) For fuel gas combustion devices subject to 40 CFR 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of 40 CFR 60.105. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO2 and 25 percent oxygen (O2).

(ii) The SO_2 monitoring level equivalent to the H_2S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(b) In place of the SO_2 monitor in paragraph (a)(3) of 40 CFR 60.105, an instrument for continuously monitoring and recording the concentration (dry basis) of H2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H2S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned.

(iii) The performance evaluations for this H2S monitor under Sec. 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(c) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to 40 CFR 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm O2 and 25 percent O2.

(ii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(d) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105 are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(e) The Permittee shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the 40 CFR 60.13(e) performance evaluation.

(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

D.2.20 General Compliance Requirements [40 CFR 63.1570] [326 IAC 20-50-1]

(a) The Permittee shall comply with all of the non-opacity standards in 40 CFR Part 63 during the times specified in 40 CFR 63.6(f)(1).

(b) The Permittee shall comply with the opacity and visible emission limits in this subpart during the times specified in 40 CFR 63.6(h)(1).

(c) The Permittee shall always operate and maintain the affected source, including air pollution control and monitoring equipment, according to the provisions in 40 CFR 63.6(e)(1)(i). During the period between the compliance date specified for the affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, the Permittee shall maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(d) The Permittee shall develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in 40 CFR 63.6(e)(3).

(e) During periods of startup, shutdown, and malfunction, the Permittee shall operate in accordance with the SSMP.

(f) The Permittee shall report each instance in which the Permittee did not meet each emission limitation and each applicable operating limit in this subpart. This includes periods of startup, shutdown, and malfunction. The Permitte also shall report each instance in which the Permittee did not meet the applicable work practice standards in this subpart. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in 40 CFR 63.1575.

(g) Consistent with 40 CFR 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates to IDEM, OAQ's satisfaction that the Permittee was operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). IDEM, OAQ will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 40 CFR 63.6(e) and the contents of the SSMP.

D.2.21 Monitoring Installation, Operation, and Maintenance Requirements [40 CFR 63.1572] [326 IAC 20-50-1]

(a) The Permittee shall install, operate, and maintain each continuous emission monitoring system according to the requirements in 40 CFR 63.1572 paragraphs (a)(1) through (4).
  (1) The Permittee shall install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of this subpart.
  (2) If the Permittee uses a continuous emission monitoring system to meet the NSPS CO or SO2 limit, then the Permittee shall conduct a performance evaluation of each continuous emission monitoring system according to the requirements in 40 CFR 63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.
  (3) As specified in 40 CFR 63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
  (4) Data must be reduced as specified in 40 CFR 63.8(g)(2).

(b) The Permittee shall install, operate, and maintain each continuous opacity monitoring system according to the requirements in 40 CFR 63.1572 paragraphs (b)(1) through (3).
  (1) Each continuous opacity monitoring system must be installed, operated, and maintained according to the requirements in Table 40 of this subpart.
  (2) If the Permittee uses a continuous opacity monitoring system to meet the NSPS opacity limit, then the Permittee shall conduct a performance evaluation of each continuous opacity monitoring system according to the requirements in 40 CFR 63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.
  (3) As specified in 40 CFR 63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(c) The Permittee shall install, operate, and maintain each continuous parameter monitoring system according to the requirements in 40 CFR 63.1572 paragraphs (c)(1) through (7).

(1) Each continuous parameter monitoring system must be installed, operated, and maintained according to the requirements in Table 41 of this subpart and in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately.

(2) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. The Permittee shall have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).

(3) Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.

(4) Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day. The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.

(5) Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.

(d) The Permittee shall monitor and collect data according to the requirements in 40 CFR 63.1572 paragraphs (d)(1) and (2).

(1) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(2) The Permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. The Permittee shall use all the data collected during all other periods in assessing the operation of the control device and associated control system.

D.2.22 General Compliance Requirements [40 CFR 63.7505]

Pursuant to 40 CFR 63.7505, the Permittee shall comply with the following requirements:

(a) The Permittee shall be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) The Permittee shall always operate and maintain the affected source, including air pollution control and monitoring equipment, according to the revisions in §63.6(e)(1)(i).

(c) The Permittee can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit. Otherwise, The Permittee must demonstrate compliance using performance testing.

(d) If the Permittee demonstrate compliance with any applicable emission limit through performance testing, the Permittee must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of 40 CFR 63.7505. This requirement also applies if the Permittee petitions the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each continuous monitoring system (CMS) required in 40 CFR 63.7505, the Permittee must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of 40 CFR 63.7505. The Permittee must submit this site-specific monitoring plan at least 60 days before initial performance evaluation of the CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and
(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(2) In the site-specific monitoring plan, the Permittee must also address paragraphs (d)(2)(i) through (iii) of this 40 CFR 63.7505.
(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (3), and (4)(ii);
(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and
(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(3) The Permittee shall conduct a performance evaluation of each CMS in accordance with the site-specific monitoring plan.

(4) The Permittee shall operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If the Permittee has an applicable emission limit or work practice standard, the Permittee must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

D.2.23 Monitoring, Installation, Operation, and Maintenance Requirements [40 CFR 63.7525]

Pursuant to 40 CFR 63.7525, the Permittee shall comply with the following requirements:

(a) If the Permittee has an applicable work practice standard for carbon monoxide, and the boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, then the Permittee must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of 40 CFR 63.7525 by the compliance date specified in §63.7495.
(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to §63.7505(d).
(2) The Permittee must conduct a performance evaluation of each CEMS according to the requirements in §63.8 and according to PS 4A of 40 CFR part 60, appendix B.
(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
(4) The CEMS data must be reduced as specified in §63.8(g)(2).
(5) The Permittee must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.
(6) For purposes of calculating data averages, the Permittee must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when the boiler or process heater is operating at less than 50 percent of its rated capacity. The Permittee must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitute a deviation from the monitoring requirements.

(b) If the Permittee has an applicable opacity operating limit, then the Permittee must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of 40 CFR 63.7525 by the compliance date specified in §63.7495.
(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.
(2) The Permittee must conduct a performance evaluation of each COMS according to the requirements in §63.8 and according to PS 1 of 40 CFR part 60, appendix B.
(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) The Permittee must include in the site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) The Permittee must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) The Permittee must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.

(c) If the Permittee has an operating limit that requires the use of a CMS, then the Permittee must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of 40 CFR 63.7525 by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. The Permittee must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent , not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, the Permittee must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. The Permittee must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of 40 CFR 63.7525.

(5) Record the results of each inspection, calibration, and validation check.

(d) If the Permittee has an operating limit that requires the use of a flow measurement device, then the Permittee must meet the requirements in paragraphs (c) and (d)(1) through (4) of 40 CFR 63.7525.

(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.

(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) Conduct a flow sensor calibration check at least semiannually.

(e) If the Permittee has an operating limit that requires the use of a pressure measurement device, then the Permittee must meet the requirements in paragraphs (c) and (e)(1) through (6) of 40 CFR 63.7525.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(f) If the Permittee has an operating limit that requires the use of a pH measurement device, then the Permittee must meet the requirements in paragraphs (c) and (f)(1) through (3) of this 40 CFR 63.7525.

(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(g) If the Permittee has an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), then the Permittee must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(h) If the Permittee has an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), then the Permittee must meet the requirements in paragraphs (c) and (h)(1) through (3) of 40 CFR 63.7525.
(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.
(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.
(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.

(i) If the Permittee elects to use a fabric filter bag leak detection system to comply with the requirements of this subpart, then the Permittee must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of 40 CFR 63.7525.
(1) The Permittee must install and operate a bag leak detection system for each exhaust stack of the fabric filter.
(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA-454/R-98-015, September 1997.
(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.
(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.
(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.
(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.
(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.
(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

D.2.24 Initial Compliance with the Emission Limits and Work Practice Standards [40 CFR 63.7530]

Pursuant to 40 CFR 63.7530, the Permittee shall comply with the following requirements:

(a) The Permitte must demonstrate initial compliance with each emission limit and work practice standard that applies to Permittee by either conducting initial performance tests and establishing operating limits, as applicable, according to §63.7520, paragraph (c) of 40 CFR 63.7530, and Tables 5, 7 and 8 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to §63.7521, paragraph (d) of 40 CFR 63.7530, and Tables 6 and 8 to this subpart.

(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(c) If the Permittee demonstrates compliance through performance testing, then the Permittee must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to the Permittee according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (c)(4) of 40 CFR 63.7530, as applicable. The Permittee must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of 40 CFR 63.7530, as applicable.

(d) If the Permittee elects to demonstrate compliance with an applicable emission limit through fuel analysis, then the Permittee must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (d)(1) through (5) of 40 CFR 63.7505.

(e) The Permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

D.2.25 Continuous Compliance Requirements [40 CFR 63.7535]

Pursuant to 40 CFR 63.7535, the Permittee shall comply with the following requirements:

(a) The Permittee must monitor and collect data according to 40 CFR 63.7535 and the site-specific monitoring plan required by §63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) The Permittee may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The Permittee must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.

Pursuant to 40 CFR 63.7540, the Permittee shall use the following to demonstrate continuous compliance with the emission limits and work practice standards.

(a) The Permittee must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to the Permittee according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of 40 CFR 63.7540.

(b) The Permittee must report each instance in which the Permittee did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply. The Permittee must also report each instance during a startup, shutdown, or malfunction when the Permittee did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, the Permittee must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §§63.6(e)and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates to the EPA Administrator's satisfaction that the Permittee was operating in accordance with the SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

(e) Following the compliance date, the Permittee must demonstrate continuous compliance under the emission averaging provision with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of 40 CFR 63.7541.

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

D.2.26 Record Keeping Requirements

(a) To document compliance with Conditions D.2.5 and D.2.19, the Permittee shall maintain records of the concentration of H_2S in fuel gases by methods defined under Condition D.2.19.

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

D.2.27 Record Keeping Requirements [40 CFR 63.1576]

(a) The Permittee shall keep the records specified in 40 CFR 63.1576 paragraphs (a)(1) through (3).
  (1) A copy of each notification and report that the Permittee submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status that the Permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).
  (2) The records in 40 CFR 63.6(e)(1)(iii) through (v) related to startup, shutdown, and malfunction.
  (3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in 40 CFR 63.10(b)(2)(viii).

(b) To document compliance with Conditions D.2.20 the Permittee shall maintain records of all the applicable parameters listed in Condition D.2.20.

(c) To document compliance with Condition D.2.21, the Permittee shall keep the records required in 40 CFR 63.1576 paragraphs (b)(1) through (5).
  (1) Records described in 40 CFR 63.10(b)(2)(vi) through (xi).
  (2) Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in 40 CFR 63.6(h)(7)(i) and (ii).
  (3) Previous (i.e., superceded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).
  (4) Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in 40 CFR 63.8(f)(6)(i).
  (5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(d) The Permittee shall keep the records in 40 CFR 63.6(h) for visible emission observations.

(e) The Permittee shall keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); and Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines) to show continuous compliance with each applicable emission limitation.

(f) The Permittee shall keep a current copy of the operation, maintenance, and monitoring plan onsite and available for inspection. The Permittee also shall keep records to show continuous compliance with the procedures in the operation, maintenance, and monitoring plan.

(g) The Permittee shall keep the records of any changes that affect emission control system performance including, but not limited to, the location at which the vent stream is introduced into the flame zone for a boiler or process heater.

(h) The records must be in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).

(i) As specified in 40 CFR 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(j) The Permittee shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The Permittee can keep the records offsite for the remaining 3 years.

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

D.2.28 Notifications [40 CFR Part 63.1574] [326 IAC 20-50-1]

(a) Except as allowed in 40 CFR 63.1574 paragraphs (a)(1) through (3), the Permittee shall submit all of the applicable notifications in 40 CFR 63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) by the dates specified below.

(1) The Permittee shall submit the notification of intention to construct or reconstruct according to 40 CFR 63.9(b)(5).

(2) The Permittee must submit the notification of intent to conduct a performance test required in 40 CFR 63.7(b) at least 30 calendar days before the performance test is scheduled to begin.

(3) If the Permittee is required to conduct a performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, then the Permittee shall submit a notification of compliance status according to 40 CFR 63.9(h)(2)(ii). The Permittee can submit this information in an operating permit application, in an amendment to an operating permit application, in a separate submission, or in any combination. If the required information has been submitted previously, the Permittee does not have to provide a separate notification of compliance status and may refer to the earlier submissions instead of duplicating and resubmitting the previously submitted information.

(i) For each initial compliance demonstration that does not include a performance test, the Permittee must submit the Notification of Compliance Status no later than 30 calendar days following completion of the initial compliance demonstration.

(ii) For each initial compliance demonstration that includes a performance test, the Permittee must submit the notification of compliance status, including the performance test results, no later than 150 calendar days after the compliance date specified for the affected source in 40 CFR 63.1573.

(b) As specified in 40 CFR 63.9(b)(3), if the Permittee starts a new or reconstructed affected source on or after April 11, 2002, then the Permittee shall submit the initial notification no later than 120 days after the source becomes subject to this subpart.

(c) The Permittee shall include the information in Table 42 of this subpart in the notification of compliance status.

(d) If the Permittee requests an extension of compliance for an existing catalytic cracking unit as allowed in 40 CFR 63.1563(c), the Permittee shall submit a notification to IDEM, OAQ containing the required information by October 13, 2003.

(e) As required by this subpart, the Permittee shall prepare and implement an operation, maintenance, and monitoring plan for each affected source, control system, and continuous monitoring system. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures the Permittee will follow.

(1) The Permittee shall submit the plan to IDEM, OAQ for review and approval along with the notification of compliance status. While the Permittee does not have to include the entire plan in the part 70 or 71 permit, the Permittee shall include the duty to prepare and implement the plan as an applicable requirement in the part 70 or 71 operating permit. The Permittee shall submit any changes to IDEM, OAQ for review and approval and comply with the plan until the change is approved.

(2) Each plan must include, at a minimum, the information specified in 40 CFR 63.1574 paragraphs (f)(2)(i) through (x).

(i) Process and control device parameters to be monitored for each affected source, along with established operating limits.

(ii) Procedures for monitoring emissions and process and control device operating parameters for each affected source.

(iii) Procedures that the Permittee will use to determine the coke burn-rate, the volumetric flow rate (if the Permittee uses process data rather than direct measurement), and the rate of combustion of liquid or solid fossil fuels if the Permittee uses an incinerator-waste heat boiler to burn the exhaust gases from a catalyst regenerator.

(iv) Procedures and analytical methods the Permittee will use to determine the equilibrium catalyst Ni concentration, the equilibrium catalyst Ni concentration monthly rolling average, and the hourly or hourly average Ni operating value.

(v) Procedures the Permittee will use to determine the pH of the water (or scrubbing liquid) exiting a wet scrubber if the Permittee uses pH strips.

(vi) Procedures the Permittee will use to determine the HCl concentration of gases from a semi-regenerative catalytic reforming unit with an internal scrubbing system (i.e., no add-on control device) when the Permittee uses a colormetric tube sampling system, including procedures for correcting for pressure (if applicable to the sampling equipment).

(vii) Procedures the Permittee will use to determine the gas flow rate for a catalytic cracking unit if the Permittee uses the alternative procedure based on air flow rate and temperature.

(viii) Monitoring schedule, including when the Permittee will monitor and will not monitor an affected source (e.g., during the coke burn-off, regeneration process).

(ix) Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system the Permittee uses to meet an emission limit in this subpart. This plan must include procedures the Permittee will use for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.

(x) Maintenance schedule for each affected source, monitoring system, and control device that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.

D.2.29 Reporting Requirements [40 CFR Part 63.1575] [326 IAC 20-50-1]

Pursuant to 40 CFR 63.1576, the following Reporting Requirements shall apply:

(a) The Permittee shall submit each applicable report in Table 43 of this subpart.

(b) Unless IDEM, OAQ has approved a different schedule, the Permittee shall submit each report by the date in Table 43 of this subpart and according to the requirements in 40 CFR 63.1576 paragraphs (b)(1) through (5).

(1) The first compliance report must cover the period beginning on the compliance date that is specified for the affected source in 40 CFR 63.1563 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the affected source in 40 CFR 63.1563.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for the affected source in 40 CFR 63.1563.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or 71 of this chapter, and if IDEM, OAQ has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the Permittee may submit the first and subsequent compliance reports according to the dates IDEM, OAQ has established instead of according to the dates in 40 CFR 63.1576 paragraphs (b)(1) through (4).

(c) The compliance report must contain the information required in 40 CFR 63.1576 paragraphs (c)(1) through (4).

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If there are no deviations from any applicable emission limitation and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

(d) For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where the Permittee is not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the compliance report must contain the information in 40 CFR 63.1576 paragraphs (c)(1) through (3) and the information in 40 CFR 63.1576 paragraphs (d)(1) through (3).

(1) The total operating time of each affected source during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(e) For each deviation from an emission limitation occurring at an affected source where the Permittee is using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, the Permittee shall include the information in 40 CFR 63.1576 paragraphs (d)(1) through (3) and the information in 40 CFR 63.1576 paragraphs (e)(1) through (13).

(1) The date and time that each malfunction started and stopped.
(2) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high-level checks.
(3) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in 40 CFR 63.8(c)(8).
(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.
(5) A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during that reporting period.
(6) A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.
(7) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.
(8) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.
(9) An identification of each HAP that was monitored at the affected source.
(10) A brief description of the process units.
(11) The monitoring equipment manufacturer(s) and model number(s).
(12) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.
(13) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.

(f) The Permittee shall include the information required in 40 CFR 63.1576 paragraphs (f)(1) through (2) in each compliance report, if applicable.

(1) A copy of any performance test done during the reporting period on any affected unit. The report may be included in the next semiannual report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, the Permittee shall submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.

(2) Any requested change in the applicability of an emission standard (e.g., Permittee wants to change from the PM standard to the Ni standard for catalytic cracking units or from the HCl concentration standard to percent reduction for catalytic reforming units) in the periodic report. The Permittee shall include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.

(g) The Permittee may submit reports required by other regulations in place of or as part of the compliance report if they contain the required information.

(h) The reporting requirements in 40 CFR 63.1576 paragraphs (h)(1) and (2) apply to startups, shutdowns, and malfunctions:

(1) When actions taken to respond are consistent with the plan, the Permittee is not required to report these events in the semiannual compliance report and the reporting requirements in 40 CFR 63.6(e)(3)(iii) and 63.10(d)(5) do not apply.

(2) When actions taken to respond are not consistent with the plan, the Permittee shall report these events and the response taken in the semiannual compliance report. In this case, the reporting requirements in 40 CFR 63.6(e)(3)(iv) and 63.10(d)(5) do not apply.

(i) If IDEM, OAQ has approved a period of planned maintenance for the catalytic cracking unit according to the requirements in 40 CFR 63.1576 paragraph (j), the Permittee shall include the following information in the compliance report.

(1) In the compliance report due for the 6-month period before the routine planned maintenance is to begin, the Permittee shall include a full copy of the written request to IDEM, OAQ and written approval received from IDEM, OAQ.

(2) In the compliance report due after the routine planned maintenance is complete, the Permittee must include a description of the planned routine maintenance that was performed for the control device during the previous 6-month period, and the total number of hours during those 6 months that the control device did not meet the emission limitations and monitoring requirements as a result of the approved routine planned maintenance.

(j) If Permittee owns or operates multiple catalytic cracking units that are served by a single wet scrubber emission control device (e.g., a Venturi scrubber), the Permittee may request IDEM, OAQ to approve a period of planned routine maintenance for the control device needed to meet requirements in the operation, maintenance, and monitoring plan. The Permittee must present data to IDEM, OAQ demonstrating that the period of planned maintenance results in overall emissions reductions. During this pre-approved time period, the emission control device may be taken out of service while maintenance is performed on the control device and/or one of the process units while the remaining process unit(s) continue to operate. During the period the emission control device is unable to operate, the emission limits, operating limits, and monitoring requirements applicable to the unit that is operating and the wet scrubber emission control device do not apply. IDEM, OAQ may require that the Permittee take specified actions to minimize emissions during the period of planned maintenance.

(1) The Permittee must submit a written request to IDEM, OAQ at least 6 months before the planned maintenance is scheduled to begin with a copy to the EPA Regional Administrator.

(2) Permittee's written request must contain the information in 40 CFR 63.1575 paragraphs (j)(2)(i) through (v).

(i) A description of the planned routine maintenance to be performed during the next 6 months and why it is necessary.

(ii) The date the planned maintenance will begin and end.

(iii) A quantified estimate of the HAP and criteria pollutant emissions that will be emitted during the period of planned maintenance.

(iv) An analysis showing the emissions reductions resulting from the planned maintenance as opposed to delaying the maintenance until the next unit turnaround.

(v) Actions the Permittee will take to minimize emissions during the period of planned maintenance.

D.2.30 Notification Requirements [40 CFR Part 63.7545]

Pursuant to 40 CFR 63.7545, the Permittee shall comply with the following notification requirements:

(a) The Permittee must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply by the dates specified.

(b) As specified in §63.9(b)(2), if the Permitte startup the affected source before the date of publication of the final rule in the federal register, the Permittee must submit an Initial Notification not later than 120 days after the date of publication of the final rule in the federal register. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of 40 CFR 63.7545, as applicable.

(1) If the affected source has an annual capacity factor of greater than 10 percent, then the Initial Notification must include the information required by §63.9(b)(2).

(2) If the affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), then the Initial Notification must include the information required by §63.9(b)(2) and also a signed statement indicating that affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(c) As specified in §63.9(b)(3), if the Permittee startup a new or reconstructed affected source on or after the date of publication of the final rule in the federal register, the Permittee must submit an Initial Notification not later than 120 days after its become subject to this subpart. The Initial Notification must include the information required in paragraphs (c)(1) and (2) of 40 CFR 63.7545, as applicable.

(1) If the affected source has an annual capacity factor of greater than 10 percent, then the Initial Notification must include the information required by §63.9(b).

(2) If the affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, then the Initial Notification must include the information required by §63.9(b) and a signed statement indicating that affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(d) If the Permittee is required to conduct a performance test then the Permittee must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(e) If the Permittee is required to conduct an initial compliance demonstration as specified in §63.7530(a), then the Permittee must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, the Permittee must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(l) through (9) of 40 CFR 63.7545, as applicable.

D.2.31 Recordkeeping Requirements [40 CFR Part 63.7555 and 7560]

Pursuant to 40 CFR 63.7555, the Permittee shall comply with the following recordkeeping requirements:

(a) The Permittee must keep records according to paragraphs (a)(1) through (3) of 40 CFR 63.7555.

(1) A copy of each notification and report that the Permittee submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that the Permittee submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, the Permittee must keep records according to paragraphs (b)(1) through (5) of 40 CFR 63.7555.
(1) Records described in §63.10(b)(2)(vi) through (xi).
(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).
(3) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).
(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).
(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) The Permittee must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to the Permittee.

(d) For each boiler or process heater subject to an emission limit, the Permittee must also keep the records in paragraphs (d)(1) through (5) of 40 CFR 63.7555.
(1) The Permittee must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.
(2) The Permittee must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.
(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 1 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 5 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.
(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 2 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 6 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 3 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 7 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If the boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, the Permittee must keep the records in paragraphs (e)(1) and (2) of 40 CFR 63.7555.
(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.
(2) Fuel use records for the days the boiler or process heater was operating.

(f) The records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(g) As specified in §63.10(b)(1), the Permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(h) The Permittee must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Permittee can keep the records off site for the remaining 3 years.

D.2.32 Reporting Requirements [40 CFR Part 63.7550]

Pursuant to 40 CFR 63.7550, the Permittee shall comply with the following reporting requirements:

(a) The Permittee must submit each report in Table 9 to this subpart that applies to the Permittee.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), the Permittee must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of 40 CFR 63.7550.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for the affected source in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for the source in §63.7495.
(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in §63.7495.
(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.
(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the Permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of 40 CFR 63.7550.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of 40 CFR Part 63.7550.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where the Permittee is not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of 40 CFR 63.7550 and the information required in paragraphs (d)(1) through (4) of 40 CFR 63.7550. This includes periods of startup, shutdown, and malfunction.
(1) The total operating time of each affected source during the reporting period.
(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which the Permittee deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where the Permittee is using a CMS to comply with that emission limit, operating limit, or work practice standard, the Permittee must include the information in paragraphs (c)(1) through (10) of 40 CFR 63.7550 and the information required in paragraphs (e)(1) through (12) of 40 CFR 63.7550. This includes periods of startup, shutdown, and malfunction and any deviations from the site-specific monitoring plan as required in §63.7505(d).

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If the Permittee operates a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and the Permittee intends to use a fuel other than natural gas or equivalent to fire the affected unit, then the Permittee must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of 40 CFR 7550.

SECTION D.3 FACILITY OPERATION CONDITIONS

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

The following storage vessels:

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

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
1	fixed roof cone tank	404,418	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	075;
2	fixed roof cone tank	404,502	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	076;
3	fixed roof cone tank	404,334	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	077;
4	fixed roof cone tank	118,272	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	018;
5	fixed roof cone tank	120,456	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	019;
6	fixed roof cone tank	120,456	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	020;
7	fixed roof cone tank	126,000	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	078;
8	fixed roof cone tank	126,000	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	079;
9	fixed roof cone tank	204,204	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	023;
10	fixed roof cone tank	121,590	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1940	024;
11A	fixed roof cone tank	8,820	168,000	oil water / mixture	1972	080;
11B	fixed roof cone tank	8,820	168,000	oil water / mixture	1972	081;
12	fixed roof cone tank	6,090	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1988	082;
15	fixed roof cone tank	24,654	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1941	083;
17	fixed roof cone tank	997,584	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1941	030;
18	internal floating roof tank,/mechanical primary seal	1,052,013	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	2003	037;
19	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	616,938	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	032;
21	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	1,002,750	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	034;
22A	fixed roof cone tank	1,050,000	84,000	hydrocarbon with vapor pressure of No. 2 fuel oil o less	2003	120;
24	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	588,714	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1985	037;
25	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	656,614	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	038;
26	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	1,006,068	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	039;

33	fixed roof cone tank	2,262,960	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1946	085;
34	fixed roof cone tank	984,480	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1946	045;
35	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	997,962	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1946	046;;
36	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,163,924	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1946	047;
37	fixed roof cone tank	2,247,126	210,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1946	048;
38	fixed roof cone tank	2,248,386	210,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1948	049;;
39	fixed roof cone tank	2,250,234	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1948	050;
40	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,222,388	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1949	051;
41	fixed roof cone tank/internal floating roof tank,/lmechanical primary seal	2,204,244	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1949	052;
42	fixed roof cone tank	2,261,574	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1950	053;
43	fixed roof cone tank	2,254,098	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1951	054;
44	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,310,000	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1951	055;
45	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,310,000	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1951	056;
46	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	3,402,000	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1955	057;
47	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	5,040,000	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1976	058;
48	fixed roof cone tank/external floating roof tank /mechanical primary seal	4,032,000	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1958	059;
49	fixed roof cone tank/ external floating roof tank /mechanical primary seal	4,032,000	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1958	060;
50	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	3,934,266	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1965	061;
51	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	3,937,266	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1973	062;
52	fixed roof cone tank	3,935,148	336,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1976	063;
53	fixed roof cone tank	16,926	168,000	Ethanol,	1985	086;
54	fixed roof cone tank	16,926	168,000	Ethanol,	1985	087;
55	fixed roof cone tank	11,634	168,000	Ethanol,	1980	088;
56	fixed roof cone tank	11,634	168,000	Ethanol,	1980	089;
58	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1980	102;
159	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1988	103;
160	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1994	104;
161	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1994	105;

162	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1994	106;
163	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1983	107;
164	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1983	108;
165	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1985	109;
166	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1985	110;
167	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1985	111;
168	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naphtha,	1988	112;
169	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1989	113;
125	**fixed roof cone tank**	**157,000**	**6,000**	**hydrocarbon with vapor pressure of No.2 fuel oil or less**	**2005**	**015;**

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

D.3.1 General Provisions Relating to NSPS and NESHAP [326 IAC 12-1-1] [40 CFR Part 60, Subpart A] [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

(a) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to tanks 47 and 52 described in this section except when otherwise specified in 40 CFR Part 60, Subpart K.

(b) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to tanks 12, 18, 24, 53, 54, 159, 160, 161, 162, 165, 166, 167, 168 and 169 described in this section except when otherwise specified in 40 CFR Part 60, Subpart Kb.

(c) The provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to certain of the tanks described in this section except when otherwise specified in 40 CFR Part 63, Subpart CC.

(2) an analysis showing the capacity of the storage vessel.

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

D.3.12 VOC Record Keeping Requirements [326 IAC 8-4-3] [40 CFR 60.115b][40 CFR 60.110b]

(a) The Permittee shall comply with the record keeping requirements of 326 IAC 8-4-3. The following records are required for tank Nos. 18 and 24:

(1) The types of volatile petroleum liquids stored,

(2) The maximum true vapor pressure of the liquids stored, and

(3) The results of the inspections performed on the tanks.

Such records will be maintained for a period of two (2) years and shall be made available to the commissioner upon written request.

(b) Pursuant to 40 CFR Part 60.110b, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels), storage tanks identified as 22A and 125 are subject to following record keeping requirements.

The Permittee shall maintain permanent records at the source in accordance with (1) through (3) below:

(1) the dimension of the storage vessel;

(2) an analysis showing the capacity of the storage vessel; and

(3) vapor pressure of organic liquid stored in tanks 22A and 125.

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

SECTION D.4 FACILITY OPERATION CONDITIONS

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

(a) Two (2) sets of Oil/water Separators **equipped with covers for VOC control**, identified as 071;
(b) one (1) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(c) pipeline Valves - Gas, identified as 090;
(d) pipeline Valves - Light Liquid, identified as 091;
(e) pipeline Valves - Heavy Liquid, identified as 092;
(f) pipeline Valves - Hydrogen, identified as 093;
(g) open Ended Valves, identified as 094;
(h) flanges, identified as 095;
(i) pump Seals Light Liquid, identified as 096;
(j) pump Seals Heavy Liquid, identified as 097;
(k) compressor Seals - Gas, identified as 098;
(l) compressor Seals - Heavy Liquid, identified as 099;
(m) drains, identified as 100;
(n) vessel Relief Valves, identified as 101;
(o) cooling Towers, identified as 119; and
(p) process units made up of vessels, piping, exchangers, identified as PENEX.
(q) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of:
  (1) pipeline Valves - Gas, identified as 090;
  (2) pipeline Valves - Light Liquid, identified as 091;
  (3) pipeline Valves - Heavy Liquid, identified as 092;
  (4) pipeline Valves - Hydrogen, identified as 093;
  (5) open Ended Valves, identified as 094;
  (6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
  (7) flanges, identified as 095;
  (8) pump Seals Light Liquid, identified as 096;
  (9) pump Seals Heavy Liquid, identified as 097;
  (10) compressor Seals - Gas, identified as 098;
  (11) compressor Seals - Heavy Liquid, identified as 099;
  (12) drains, identified as 100;
  (13) vessel Relief Valves, identified as 101; and
  (14) cooling Towers, identified as 119.

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

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

D.4.1 General Provisions Relating to NSPS and NESHAP [326 IAC 12-1-1] [40 CFR Part 60, Subpart A] [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

(a) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 60, Subpart GGG as an “affected facility,” except when otherwise specified in 40 CFR Part 60, Subpart GGG.

(b) The provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 63, Subpart CC as an “affected facility,” except when otherwise specified in 40 CFR Part 63, Subpart CC.

(c) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 60, Subpart QQQ as an "affected facility," except when otherwise specified in 40 CFR Part 60, Subpart QQQ.

D.4.2 Equipment Leaks of VOC in Petroleum Refineries [326 IAC 12-1-1] [40 CFR Part 60, Subpart GGG]

Pursuant to 40 CFR 60.590 and 326 IAC 12-1-1, the provisions of 40 CFR 60, Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, which are incorporated by reference as 326 IAC 12-1-1, apply only to the equipments associated with the CCR unit (listed in Section D.1)**,** Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit and TGTU, and PENEX unit because they were constructed or modified after January 4, 1983.

D.4.3 Petroleum Refineries NESHAP [326 IAC 20-1-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.640 and 326 IAC 20-1-1, the provisions of 40 CFR 63, Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, which are incorporated by reference as 326 IAC 20-1-1, apply to affected facilities at the source because they are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act and emit or have equipment containing or contacting benzene which is one or more of the hazardous air pollutants listed in table 1 of this subpart.

D.4.4 VOC Emissions From Petroleum Refinery Wastewater Systems [326 IAC 12-1-1] [40 CFR Part 60, Subpart QQQ]

Pursuant to 40 CFR 60.690 and 326 IAC 12-1-1, the provisions of 40 CFR 60, Subpart QQQ - Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems, which are incorporated by reference as 326 IAC 12-1-1, apply to Oil/Water Separators and associated wastewater drains because these facilities are located at a petroleum refinery and are being constructed or modified after the rule applicability date of May 4, 1987.

D.4.5 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries [40 CFR 60.592] [326 IAC 12]

Pursuant to 40 CFR 60.592, following standards apply only to the equipment associated with the CCR unit (listed in Section D.1), Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit and TGTU, and the PENEX unit:

(a) The Permittee subject to the provisions of this subpart shall comply with the requirements of 60.482-1 to 60.482-10 as soon as practicable, but no later than 180 days after initial startup.

(b) A Permittee may elect to comply with the requirements of 40 CFR 60.483-1 and 60.483-2.

(c) A Permittee may apply to IDEM, OAQ for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the Permittee shall comply with requirements of 40 CFR 60.484.

(d) The Permittee subject to the provisions of this subpart shall comply with the provisions of 40 CFR 60.485 except as provided in 40 CFR 60.593.

(e) The Permittee subject to the provisions of this subpart shall comply with the provisions of 40 CFR 60.486 and 40 CFR 60.487.

Pursuant to 40 CFR 60.593, following standards apply only to the equipment associated with the CCR unit (listed in Section D.1) and the PENEX unit:

(a) The Permittee subject to the provisions of this subpart may comply with the following exceptions to the provisions of Subpart VV.

(b) (1) Compressors in hydrogen service are exempt from the requirements of 60.592 if a Permittee demonstrates that a compressor is in hydrogen service.

(2) Each compressor is presumed not to be in hydrogen service unless a Permittee demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E-260, E-168, or E-169 (incorporated by reference as specified in 40 CFR 60.17) shall be used.

(A) A Permittee may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When a Permittee and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) shall be used to resolve the disagreement.

(B) If a Permittee determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of 40 CFR 60.14 or 40 CFR 60.15 is exempt from 60.482 (a), (b), (c), (d), (e), and (h) provided the Permittee demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR 60.482 (a), (b), (c), (d), (e), and (h).

(d) A Permittee may use the following provision in addition to 40 CFR 60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150° C as determined by ASTM Method D-86 (incorporated by reference as specified in 60.18).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a procesic compounds of usually high molecular weight that consist of many repeated links, each link being a relatively light and simple molecule.

D.4.6 General Standards - NESHAP for Petroleum Refineries [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.642, the following shall apply to the source:

(a) Initial performance tests and initial compliance determinations shall be required only as specified in 40 CFR Part 63, Subpart CC.

(1) Performance tests and compliance determinations shall be conducted according to the schedule and procedures specified in this subpart.

(2) The Permittee shall notify the Administrator of the intention to conduct a performance test at least 30 days before the performance test is scheduled.

(3) Performance tests shall be conducted according to the provisions of 40 CFR 63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, a Permittee shall operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction.

(4) Data shall be reduced in accordance with the EPA-approved methods specified in the applicable section or, if other test methods are used, the data and methods shall be validated according to the protocol in Method 301 of appendix A of this part.

(b) The Permittee subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(c) All reports required under this subpart shall be sent to the Administrator at the addresses listed in 40 CFR 63.13 of subpart A of this part. If acceptable to both the Administrator and the Permittee of a source, reports may be submitted on electronic media.

(d) The Permittee of an existing source subject to the requirements of this subpart shall control emissions of organic HAPs to the level represented by the equation in 40 CFR 63.642(g).

(e) The Permittee of a new source subject to the requirements of this subpart shall control emissions of organic HAPs to the level represented by the equation in 40 CFR 63.642(g).

(f) The Permittee of an existing source shall demonstrate compliance with the emission standard in 40 CFR 63.642 paragraph (g) by following the procedures specified in 40 CFR 63.642 paragraph (k) for all emission points, or by following the emissions averaging compliance approach specified in 40 CFR 63.642 paragraph (l) for specified emission points and the procedures specified in 40 CFR 63.642 paragraph (k) for all other emission points within the source.

(g) The Permittee of a new source shall demonstrate compliance with the emission standard in 40 CFR 63.642 paragraph (h) only by following the procedures in 40 CFR 63.642 paragraph (k). The Permittee of a new source may not use the emissions averaging compliance approach.

(h) The Permittee of an existing source may comply, and the Permittee of a new source shall comply, with the miscellaneous process vent provisions in 40 CFR 63.643 through 63.645, the storage vessel provisions in 40 CFR 63.646, the wastewater provisions in 40 CFR 63.647, and the gasoline loading rack provisions in 40 CFR 63.650 of this subpart.
  (1) The Permittee using this compliance approach shall also comply with the requirements of 40 CFR 63.654 as applicable.
  (2) The Permittee using this compliance approach is not required to calculate the annual emission rate specified in 40 CFR 63.642 paragraph (g).

(i) The Permittee of an existing source may elect to control some of the emission points within the source to different levels than specified under 40 CFR 63.643 through 63.647, 40 CFR 63.650 and 63.651 by using an emissions averaging compliance approach as long as the overall emissions for the source do not exceed the emission level specified in 40 CFR 63.642 paragraph (d). The Permittee using emissions averaging shall meet the requirements in 40 CFR 63.642 paragraphs (i)(1) and (i)(2).
  (1) Calculate emission debits and credits for those emission points involved in the emissions average according to the procedures specified in 40 CFR 63.652; and
  (2) Comply with the requirements of 40 CFR 63.652, 63.653, and 63.654, as applicable.

(j) A State may restrict the Permittee of an existing source to using only the procedures in 40 CFR 63.642 paragraph (k) to comply with the emission standard in 40 CFR 63.642 paragraph (g) of this section. Such a restriction would preclude the source from using an emissions averaging compliance approach.

D.4.7 Storage Vessel Provisions [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.646, the following shall apply to the storage vessels:

(a) Each Permittee of a Group 1 storage vessel subject to this subpart shall comply with the requirements of 40 CFR 63.119 through 63.121 except as provided in paragraphs (b) through (l) of this section.

(b) As used in this section, all terms not defined in 40 CFR 63.641 shall have the meaning given them in 40 CFR part 63, Subparts A or G. The Group 1 storage vessel definition presented in 40 CFR 63.641 shall apply in lieu of the Group 1 storage vessel definitions presented in tables 5 and 6 of 40 CFR 63.119 of Subpart G of this part.

(1) A Permittee may use good engineering judgement or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(2) When a Permittee and IDEM, OAQ do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new source, Method 18 of 40 CFR part 60, appendix A shall be used.

(c) The following paragraphs do not apply to storage vessels at existing sources subject to this subpart: 40 CFR 63.119 (b)(5), (b)(6), (c)(2), and (d)(2).

(d) References shall apply as specified in 40 CFR 63.646 paragraphs (d)(1) through (d)(10).

(e) When complying with the inspection requirements of 40 CFR 63.120 of Subpart G of this part, the Permittee of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.

(f) Paragraphs (f)(1), (f)(2), and (f)(3) of 40 CFR 63.646 apply to Group 1 storage vessels at existing sources.

(g) Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

(h) References in 40 CFR 63.119 through 63.121 to 40 CFR 63.122(g)(1), 40 CFR 63.151, and references to initial notification requirements do not apply.

(i) References to the Implementation Plan in 40 CFR 63.120, paragraphs (d)(2) and (d)(3)(i) shall be replaced with the Notification of Compliance Status report.

(j) References to the Notification of Compliance Status report in 40 CFR 63.152(b) shall be replaced with 40 CFR 63.654(f).

(k) References to the Periodic Reports in 40 CFR 63.152(c) shall be replaced with 40 CFR 63.654(g).

(l) IDEM, OAQ can waive the notification requirements of 40 CFR 63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii) for all or some storage vessels at petroleum refineries subject to this subpart. IDEM, OAQ may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in 40 CFR 63.120(a)(6) or 63.120(b)(10)(iii) for all storage vessels at a refinery or for individual storage vessels on a case-by-case basis.

D.4.8 Equipment Leak Standards [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.648, the following standards shall apply to equipment leaks:

(a) The Permittee of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60 Subpart VV and 40 CFR 63.648 paragraph (b) except as provided in 40 CFR 63.648 paragraphs (a)(1), (a)(2), and (c) through (i). The Permittee of a new source subject to the provisions of this subpart shall comply with Subpart H of this part except as provided in 40 CFR 63.648 paragraphs (c) through (i).

(1) For purposes of compliance with this section, the provisions of 40 CFR part 60, Subpart VV apply only to equipment in organic HAP service, as defined in 40 CFR 63.641 of this subpart.

(2) Calculation of percentage leaking equipment components for Subpart VV of 40 CFR part 60 may be done on a process unit basis or a sourcewide basis. Once the Permittee has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(b) The use of monitoring data generated before August 18, 1995 to qualify for less frequent monitoring of valves and pumps as provided under 40 CFR part 60 Subpart VV or Subpart H of this part and paragraph (c) of this section (i.e., quarterly or semiannually) is governed by the requirements of 40 CFR 63.648 paragraphs (b)(1) and (b)(2).

(1) Monitoring data must meet the test methods and procedures specified in 40 CFR 60.485(b) of 40 CFR part 60, Subpart VV or 40 CFR 63.180(b)(1) through (b)(5) of Subpart H of this part except for minor departures.

(2) Departures from the criteria specified in 40 CFR 60.485(b) of 40 CFR part 60 Subpart VV or 40 CFR 63.180(b)(1) through (b)(5) of Subpart H of this part or from the monitoring frequency specified in Subpart VV or in 40 CFR 63.648 paragraph (c) (such as every 6 weeks instead of monthly or quarterly) are minor and do not significantly affect the quality of the data. An example of a minor departure is monitoring at a slightly different frequency (such as every 6 weeks instead of monthly or quarterly). Failure to use a calibrated instrument is not considered a minor departure.

(c) In lieu of complying with the existing source provisions of paragraph (a) of 40 CFR 63.648 , a Permittee may elect to comply with the requirements of 40 CFR 63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of Subpart H of this part except as provided in 40 CFR 63.648 paragraphs (c)(1) through (c)(10) and (e) through (i).

(d) Upon startup of new sources, the Permittee shall comply with 40 CFR 63.163(a)(1)(ii) of Subpart H of this part for light liquid pumps and 40 CFR 63.168(a)(1)(ii) of Subpart H of this part for gas/vapor and light liquid valves.

(e) For reciprocating pumps in heavy liquid service and agitators in heavy liquid service, owners and operators are not required to comply with the requirements in 40 CFR 63.169 of Subpart H of this part.

(f) Reciprocating pumps in light liquid service are exempt from 40 CFR 63.163 and 60.482 if recasting the distance piece or reciprocating pump replacement is required.

(g) Compressors in hydrogen service are exempt from the requirements of paragraphs (a) and (c) of 40 CFR 63.648 if a Permittee demonstrates that a compressor is in hydrogen service.

(1) Each compressor is presumed not to be in hydrogen service unless a Permittee demonstrates that the piece of equipment is in hydrogen service.

(2) For a piece of equipment to be considered in hydrogen service, it must be determined that the percentage hydrogen content can be reasonably expected always to exceed 50 percent by volume.

(i) For purposes of determining the percentage hydrogen content in the process fluid that is contained in or contacts a compressor, the Permittee shall use either:

(A) Procedures that conform to those specified in 40 CFR 60.593(b)(2) of 40 part 60, Subpart GGG.

(B) Engineering judgment to demonstrate that the percentage content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume.

(aa) When a Permittee and the Administrator do not agree on whether a piece of equipment is in hydrogen service, the procedures in 40 CFR 63.648 paragraph (g)(2)(i)(A) of this section shall be used to resolve the disagreement.

(bb) If a Permittee determines that a piece of equipment is in hydrogen service, the determination can be revised only by following the procedures in 40 CFR 63.648 paragraph (g)(2)(i)(A) of this section.

(h) Each Permittee of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years.

(i) Reciprocating compressors are exempt from seal requirements if recasting the distance piece or compressor replacement is required.

D.4.9 Alternative Means of Emission Limitation: Connectors in gas/vapor service and light liquid service [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.649, the following emission limitations shall apply to connectors in gas/vapor service and light liquid service:

(a) If a Permittee elects to monitor valves according to the provisions of 40 CFR 63.648(c)(2)(ii), the Permittee shall implement one of the connector monitoring programs specified in 40 CFR 63.649 paragraphs (b), (c), or (d).

(b) Random 200 connector alternative. The Permittee shall implement a random sampling program for accessible connectors of 2.0 inches nominal diameter or greater. The program does not apply to inaccessible or unsafe-to-monitor connectors, as defined in 40 CFR 63.174 of Subpart H. The sampling program shall be implemented source-wide.

(1) Within the first 12 months after the phase III compliance date specified in 40 CFR 63.640(h), a sample of 200 connectors shall be randomly selected and monitored using Method 21 of 40 CFR part 60, appendix A.

(2) The instrument reading that defines a leak is 1,000 parts per million.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in 40 CFR 63.649 paragraph (e). A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, the connector shall be monitored for leaks within the first 3 months after its repair.

(5) After conducting the initial survey required in 40 CFR 63.649 paragraph (b)(1), the Permittee shall conduct subsequent monitoring of connectors at the frequencies specified in 40 CFR 63.649 paragraphs (b)(5)(i) through (b)(5)(iv).

(6) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(c) Connector inspection alternative. The Permittee shall implement a program to monitor all accessible connectors in gas/vapor service that are 2.0 inches (nominal diameter) or greater and inspect all accessible connectors in light liquid service that are 2 inches (nominal diameter) or greater as described in 40 CFR 63.649 paragraphs (c)(1) through (c)(7). The program does not apply to inaccessible or unsafe-to-monitor connectors.

(d) Subpart H program. The Permittee shall implement a program to comply with the provisions in 40 CFR 63.174 of this part.

(e) Delay of repair of connectors for which leaks have been detected is allowed if repair is not technically feasible by normal repair techniques without a process unit shutdown. Repair of this equipment shall occur by the end of the next process unit shutdown.

(1) Delay of repair is allowed for equipment that is isolated from the process and that does not remain in organic HAP service.
(2) Delay of repair for connectors is also allowed if:
(i) The Permittee determines that emissions of purged material resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, and
(ii) When repair procedures are accomplished, the purged material would be collected and destroyed or recovered in a control device.

(f) Any connector that is designated as an unsafe-to-repair connector is exempt from the requirements of 40 CFR 63.649 paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), or (d) if:
(1) The Permittee determines that repair personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR 63.649 paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4); or
(2) The connector will be repaired before the end of the next scheduled process unit shutdown.

(g) The Permittee shall maintain records to document that the connector monitoring or inspections have been conducted as required and to document repair of leaking connectors as applicable.

D.4.10 Emission Averaging Provisions [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.652, the Permittee of an existing source who seeks to comply with the emission standard in 63.642(g) by using emissions averaging according to 63.642(l) rather than following the provisions of sections 63.643 through 63.647, 63.650 and 63.651 shall comply with emission averaging provisions under section 63.652.

D.4.11 General Standards [40CFR 60.692-1] [326 IAC 12]

(a) Pursuant to 40 CFR 60.692-1(a), the Permittee shall comply with the requirements of 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2 for all facilities subject to the provisions of 40 CFR 60, Subpart QQQ as provided in 40 CFR 60.690, except during periods of startup, shutdown, or malfunction.

(b) Compliance with 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR 60.696.

(c) Permission to use alternative means of emission limitation to meet the requirements of 40 CFR 60.692-2 through 60.692-4 may be granted as provided in 40 CFR 60.694.

(d) Pursuant to 40 CFR 60.692-1(d), the following units are not subject to the control requirements of 40 CFR 60, Subpart QQQ:

(1) Stormwater sewer systems;
(2) Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater; and
(3) Non-contact cooling water systems.

The Permittee shall demonstrate compliance with the exclusions in paragraphs 40 CFR 60.692-1 (d)(1), (2), and (3) of this section as provided in 40 CFR 60.697(h), (i), and (j).

(e) The definitions in 40 CFR 60, Subpart QQQ, Section 60.691 are applicable to the Permittee.

D.4.12 Standards for Individual Drain Systems [40 CFR 60.692-2] [326 IAC 12]

Pursuant to 40 CFR 60.692-2, the Permittee shall comply with the following requirements:

(a) (1) Each drain shall be equipped with water seal controls.

(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.
(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.
(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.
(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in Sec. 60.692-6.

(b) (1) Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
(2) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
(3) Junction boxes shall be visually inspected initially and semiannually hereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.
(4) If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in Sec. 60.692-6.

(c) (1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.
(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.
(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in Sec. 60.692-6.

(d) Except as provided in paragraph (e) of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section.

(e) Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

D.4.13 Standards for Oil Water Separators [40CFR 60.692-3] [326 IAC 12]

Pursuant to 40 CFR 60.692-3, the Permittee shall comply with the following requirements:

(a) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in 40 CFR 60.693-2.
(1) The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.
(2) The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.
(3) If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.
(4) Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.

(5) When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in Sec. 60.692-6.

(b) Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph (a) of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of Sec. 60.692-5, except as provided in paragraph (c) of this section or in Sec. 60.693-2.

(c)(1) Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of paragraph (b) of this section, but shall meet the requirements of paragraph (a) of this section, or may elect to comply with paragraph (c)(2) of this section.

(2) The owner or operator may elect to comply with the requirements of paragraph (a) of this section for the existing fixed roof covering a portion of the separator tank and comply with the requirements for floating roofs in Sec. 60.693-2 for the remainder of the separator tank..

(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in Secs. 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

(e) Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph (a) of this section.

(f) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph (a) of this section, and not paragraph (b) of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

D.4.14 Standards for Aggregate Facilities [40CFR 60.692-4] [326 IAC 12]

Pursuant to 40 CFR 60.692-4, a new, modified, or reconstructed aggregate facility shall comply with the requirements of40 CFR 60.692-2 and 60.692-3.

D.4.15 Standards for Closed Vent Systems and Control Devices [40CFR 60.692-5] [326 IAC 12]

Pursuant to 40 CFR 60.692-5, the Permittee shall comply with the following requirements:

(a) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 deg.C (1,500 deg.F).

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.

(c) Flares used to comply with this subpart shall comply with the requirements of 40 CFR 60.18.

(d) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(e) (1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in 40 CFR 60.696.

(2) Closed vent systems shall be purged to direct vapor to the control device.

(3) A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.

(4) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(5) When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in 40 CFR 60.692-6.

D.4.16 Standards for Closed Vent Systems and Control Devices [40CFR 60.692-6] [326 IAC 12]

Pursuant to 40 CFR 60.692-6, delay of repair of facilities that are subject to 40 CFR 60, Subpart QQQ shall be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

D.4.17 Standards for Delay of Compliance [40CFR 60.692-5] [326 IAC 12]

Pursuant to 40 CFR 60.692-7, delay of compliance of modified individual drain systems with ancillary downstream treatment components shall be allowed if compliance with the provisions of 40 CFR 60, subpart QQQ cannot be achieved without a refinery or process unit shutdown. Installation of equipment necessary to comply with the provisions of 40 CFR 60, Subpart QQQ shall occur no later than the next scheduled refinery or process unit shutdown.

D.4.18 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the affected facilities and their control device.

Compliance Determination Requirements

D.4.19 Performance Test Methods and Procedures [40CFR 60.696] [326 IAC 12]

Pursuant to 40 CFR 60.696, the Permittee shall comply with the following requirements:

(a) Before using any equipment installed in compliance with the requirements of Sec. 60.692-2, Sec. 60.692-3, Sec. 60.692-4, Sec. 60.692-5, or Sec. 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(b) The Permittee of each source that is equipped with a closed vent system and control device as required in Sec. 60.692-5 (other than a flare) is exempt from Sec. 60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:
(1) Zero air (less than 10 ppm of hydrocarbon in air), and
(2) A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(c) The Permittee shall conduct a performance test initially, and at other times as requested by the Administrator, using the test methods and procedures in Sec. 60.18(f) to determine compliance of flares.

(d) After installing the control equipment required to meet Sec. 60.693-2(a) or whenever sources that have ceased to treat refinery wastewater for a period of 1 year or more are placed back into service, the owner or operator shall determine compliance with the standards in Sec. 60.693-2(a) as follows:

(1) The maximum gap widths and maximum gap areas between the primary seal and the separator wall and between the secondary seal and the separator wall shall be determined individually within 60 calendar days of the initial installation of the floating roof and introduction of refinery wastewater or 60 calendar days after the equipment is placed back into service using the following procedure when the separator is filled to the design operating level and when the roof is floating off the roof supports.

(i) Measure seal gaps around the entire perimeter of the separator in each place where a 0.32 cm (0.125 in.) diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the separator and measure the gap width and perimetrical distance of each such location.

(ii) The total surface area of each gap described in (d)(1)(i) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the wall to the seal and multiplying each such width by its respective perimetrical distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually, divide the sum for each seal by the nominal perimeter of the separator basin and compare each to the maximum gap area as specified in Sec. 60.693-2.

(2) The gap widths and total gap area shall be determined using the procedure in paragraph (d)(1) of this section according to the following frequency:

(i) For primary seals, once every 5 years.

(ii) For secondary seals, once every year.

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

D.4.20 Monitoring, Recordkeeping, and Implementation Plan for Emissions Averaging [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.653, the following monitoring, recordkeeping and implementation plan for emission averaging shall apply to storage vessels, wastewater, gasoline loading rack only when the source elects emission averaging:

(a) For each emission point included in an emissions average, the Permittee shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with 40 CFR 63.643 through 63.647, and 40 CFR 63.650 and 63.651. The specific requirements for storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in 40 CFR 63.653 paragraphs (a)(3), (a)(4) and (a)(7).

(1) The source shall implement the following procedures for each storage vessel controlled with an internal floating roof, external roof, or a closed vent system with a control device, as appropriate to the control technique:

(i) Perform the monitoring or inspection procedures in 40 CFR 63.646 of this subpart and 40 CFR 63.120 of Subpart G; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in 40 CFR 63.646 of this subpart and 40 CFR 63.120(d) of Subpart G.

(2) For each gasoline loading rack that is controlled, perform the testing and monitoring procedures specified in 40 CFR 63.425 and 63.427 of Subpart R of this part except 40 CFR 63.425(d) or 40 CFR 63.427(c).

(3) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in 40 CFR 63.643 through 63.647 and 40 CFR 63.650 and 63.651, the Permittee shall establish a site-specific monitoring parameter and shall submit the information specified in 40 CFR 63.654(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by 40 CFR 63.654 shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by 40 CFR 63.654.

(d) Each Permittee of an existing source who elects to comply with 40 CFR 63.654 (g) and (h) by using emissions averaging for any emission points shall submit an Implementation Plan.

(1) The Implementation Plan shall be submitted to the Administrator and approved prior to implementing emissions averaging. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, in a Notification of Compliance Status Report, in a Periodic Report or in any combination of these documents. If a Permittee submits the information specified in 40 CFR 63.653 paragraph (d)(2) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating the previously submitted information.

(2) The Implementation Plan shall include the information specified in 40 CFR 63.653 paragraphs (d)(2)(i) through (d)(2)(viii) for all points included in the average.

(3) The Administrator shall determine within 120 calendar days whether the Implementation Plan submitted presents sufficient information. The Administrator shall either approve the Implementation Plan, request changes, or request that the Permittee submit additional information. Once the Administrator receives sufficient information, the Administrator shall approve, disapprove, or request changes to the plan within 120 calendar days.

D.4.21 Monitoring Requirements [40CFR 60.695] [326 IAC 12]

(a) Pursuant to 40 CFR 60.695, the Permittee shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by IDEM, OAQ.

(1) Where a thermal incinerator is used for VOC emission reduction, a temperature monitoring device equipped with a continuous recorder shall be used to measure the temperature of the gas stream in the combustion zone of the incinerator. The temperature monitoring device shall have an accuracy of +/- 1 percent of the temperature being measured, expressed in deg.C, or +/- 0.5 deg.C (0.9 deg.F), whichever is greater.

(2) Where a catalytic incinerator is used for VOC emission reduction, temperature monitoring devices, each equipped with a continuous recorder shall be used to measure the temperature in the gas stream immediately before and after the catalyst bed of the incinerator. The temperature monitoring devices shall have an accuracy of +/- 1 percent of the temperature being measured, expressed in deg.C, or +/- 0.5 deg.C (0.9 deg.F), whichever is greater.

(3) Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(i) For a carbon adsorption system that regenerates the carbon bed directly onsite, a monitoring device that continuously indicates and records the volatile organic compound concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

(4) Where a flare is used for VOC emission reduction, the owner or operator shall comply with the monitoring requirements of 40 CFR 60.18(f)(2).

(b) Where a VOC recovery device other than a carbon adsorber is used to meet the requirements specified in Sec. 60.692-5(a), the owner or operator shall provide to the Administrator information describing the operation of the control device and the process parameter(s) that would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

(c) An alternative operational or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

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

D.4.22 Reporting and Record Record Keeping Requirements [326 IAC 20-10-1] [40 CFR Part 63.654, Subpart CC]

(a) Each Permittee subject to the gasoline loading rack provisions in 40 CFR 63.650 shall comply with the recordkeeping and reporting provisions in 40 CFR 63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of Subpart R of this part (listed in section D.1). These requirements are summarized in table 4 of this subpart. There are no additional reporting and recordkeeping requirements for gasoline loading racks under this subpart unless a loading rack is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in 40 CFR 63.653 and in 40 CFR 63.654 paragraphs (f)(5) and (g)(8).

(b) Each Permittee subject to the equipment leaks standards in 40 CFR 63.648 shall comply with the recordkeeping and reporting provisions in 40 CFR 63.654 paragraphs (d)(1) through (d)(6).

(1) 40 CFR 60.486 and 60.487 of Subpart VV of part 60 except as specified in 40 CFR 63.654 paragraph (d)(1)(i); or 40 CFR 63.181 and 63.182 of Subpart H of this part except for 40 CFR 63.182(b), (c)(2), and (c)(4).

(i) The signature of the Permittee (or designate) whose decision it was that a repair could not be effected without a process shutdown is not required to be recorded. Instead, the name of the person whose decision it was that a repair could not be effected without a process shutdown shall be recorded and retained for 2 years.

(2) The Notification of Compliance Status report required by 40 CFR 63.182(c) of Subpart H and the initial semiannual report required by 40 CFR 60.487(b) of 40 CFR part 60, Subpart VV shall be submitted within 150 days of the compliance date specified in 40 CFR 63.640(h); the requirements of Subpart H of this part are summarized in table 3 of this subpart.

(3) A Permittee who determines that a compressor qualifies for the hydrogen service exemption in 40 CFR 63.648 shall also keep a record of the demonstration required by 40 CFR 63.648.

(4) A Permittee must keep a list of identification numbers for valves that are designated as leakless per 40 CFR 63.648(c)(10).

(5) A Permittee must identify, either by list or location (area or refining process unit), equipment in organic HAP service less than 300 hours per year within refining process units subject to this subpart.

(6) A Permittee must keep a list of reciprocating pumps and compressors determined to be exempt from seal requirements as per 40 CFR 63.648 (f) and (i).

(c) Each Permittee of a source subject to this subpart shall submit the reports listed in 40 CFR 63.654 paragraphs (e)(1) through (e)(3) except as provided in 40 CFR 63.654 paragraph (h)(5), and shall keep records as described in 40 CFR 63.654 paragraph (i).

(1) A Notification of Compliance Status report as described in 40 CFR 63.654 paragraph (f);

(2) Periodic Reports as described in 40 CFR 63.654 paragraph (g); and

(3) Other reports as described in 40 CFR 63.654 paragraph (h).

(d) Each Permittee of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in 40 CFR 63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with 40 CFR 63.640(l)(3) and for storage vessels subject to the compliance schedule specified in 40 CFR 63.640(h)(4). Notification of Compliance Status reports required by 40 CFR 63.640(l)(3) and for storage vessels subject to the compliance dates specified in 40 CFR 63.640(h)(4) shall be submitted according to 40 CFR 63.654 paragraph (f)(6). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in 40 CFR 63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in 40 CFR 63.640(h). If a Permittee submits the information specified in 40 CFR 63.654 paragraphs (f)(1) through (f)(5) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. Each Permittee of a gasoline loading rack classified under Standard Industrial Classification Code 2911 located within a contiguous area and under common control with a petroleum refinery subject to the standards of this subpart shall submit the Notification of Compliance Status report required by Subpart R of this part within 150 days after the compliance dates specified in 40 CFR 63.640(h) of this subpart.

(1) The Notification of Compliance Status report shall include the information specified in 40 CFR 63.654 paragraphs (f)(1)(i) and (f)(1)(v).

(i) For storage vessels, this report shall include the information specified in 40 CFR 63.654 paragraphs (f)(1)(i)(A) through (f)(1)(i)(D).

(A) Identification of each storage vessel subject to this subpart, and for each Group 1 storage vessel subject to this subpart, the information specified in 40 CFR 63.654 paragraphs (f)(1)(i)(A)(1) through (f)(1)(i)(A)(3). This information is to be revised each time a Notification of Compliance Status report is submitted for a storage vessel subject to the compliance schedule specified in 40 CFR 63.640(h)(4) or to comply with 40 CFR 63.640(l)(3).

(aa) For each Group 1 storage vessel complying with 40 CFR 63.646 that is not included in an emissions average, the method of compliance (i.e., internal floating roof, external floating roof, or closed vent system and control device).

(bb) For storage vessels subject to the compliance schedule specified in 40 CFR 63.640(h)(4) that are not complying with 40 CFR 63.646, the anticipated compliance date.

(cc) For storage vessels subject to the compliance schedule specified in 40 CFR 63.640(h)(4) that are complying with 40 CFR 63.646 and the Group 1 storage vessels described in 40 CFR 63.640(l), the actual compliance date.

(B) If a closed vent system and a control device other than a flare is used to comply with 40 CFR 63.646 the Permittee shall submit:

(aa) A description of the parameter or parameters to be monitored to ensure that the control device is being properly operated and maintained, an explanation of the criteria used for selection of that parameter (or parameters), and the frequency with which monitoring will be performed; and either

(bb) The design evaluation documentation specified in 40 CFR 63.120(d)(1)(i) of Subpart G, if the Permittee elects to prepare a design evaluation; or

(cc) If the Permittee elects to submit the results of a performance test, identification of the storage vessel and control device for which the performance test will be submitted, and identification of the emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted.

(C) If a closed vent system and control device other than a flare is used, the Permittee shall submit:

(aa) The operating range for each monitoring parameter. The specified operating range shall represent the conditions for which the control device is being properly operated and maintained.

(bb) If a performance test is conducted instead of a design evaluation, results of the performance test demonstrating that the control device achieves greater than or equal to the required control efficiency. A performance test conducted prior to the compliance date of this subpart can be used to comply with this requirement, provided that the test was conducted using EPA methods and that the test conditions are representative of current operating practices.

(D) If a closed vent system and a flare is used, the Permittee shall submit:

(aa) Flare design (e.g., steam-assisted, air-assisted, or nonassisted);

(bb) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by 40 CFR 63.120(e) of Subpart G of this part; and

(cc) All periods during the compliance determination when the pilot flame is absent.

(ii) For equipment leaks complying with 40 CFR 63.648(c) (i.e., complying with the requirements of Subpart H of this part), the Notification of Compliance Report Status report information required by 40 CFR 63.182(c) of Subpart H and whether the percentage of leaking valves will be reported on a process unit basis or a sourcewide basis.

(2) If initial performance tests are required by 40 CFR 63.643 through 63.653 of this subpart, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source.

(i) For additional tests performed using the same method, the results specified in 40 CFR 63.654 paragraph (f)(1) shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(iii) Performance tests are required only if specified by 40 CFR 63.643 through 63.653 of this subpart. Initial performance tests are required for some kinds of emission points and controls. Periodic testing of the same emission point is not required.

(3) For each monitored parameter for which a range is required to be established under 40 CFR 63.120(d) of Subpart G of this part for storage vessels, the Notification of Compliance Status report shall include the information in 40 CFR 63.654 paragraphs (f)(3)(i) through (f)(3)(iii).

(i) The specific range of the monitored parameter(s) for each emission point;

(ii) The rationale for the specific range for each parameter for each emission point, including any data and calculations used to develop the range and a description of why the range ensures compliance with the emission standard.

(A) If a performance test is required by this subpart for a control device, the range shall be based on the parameter values measured during the performance test supplemented by engineering assessments and manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of permitted parameter values.

(B) If a performance test is not required by this subpart for a control device, the range may be based solely on engineering assessments and manufacturers' recommendations.

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(4) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report.

(5) For emission points included in an emissions average, the Notification of Compliance Status report shall include the values of the parameters needed for input to the emission credit and debit equations in 40 CFR 63.652(g) and (h), calculated or measured according to the procedures in 40 CFR 63.652(g) and (h), and the resulting credits and debits for the first quarter of the year. The first quarter begins on the compliance date specified in 40 CFR 63.640.

(6) Notification of Compliance Status reports required by 40 CFR 63.640(l)(3) and for storage vessels subject to the compliance dates specified in 40 CFR 63.640(h)(4) shall be submitted no later than 60 days after the end of the 6-month period during which the change or addition was made that resulted in the Group 1 emission point or the existing Group 1 storage vessel was brought into compliance, and may be combined with the periodic report. Six-month periods shall be the same 6-month periods specified in 40 CFR 63.654 paragraph (g). The Notification of Compliance Status report shall include the information specified in 40 CFR 63.654 paragraphs (f)(1) through (f)(5). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, as part of the periodic report, or in any combination of these four. If the required information has been submitted before the date 60 days after the end of the 6-month period in which the addition of the Group 1 emission point took place, a separate Notification of Compliance Status report is not required within 60 days after the end of the 6-month period. If a Permittee submits the information specified in 40 CFR 63.654 paragraphs (f)(1) through (f)(5) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(e) The Permittee of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6- month period when any of the compliance exceptions specified in 40 CFR 63.654 paragraphs (g)(1) through (g)(6) occur. The first 6- month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the compliance exceptions specified in 40 CFR 63.654 paragraphs (g)(1) through (g)(6) occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emissions averages, as provided in 40 CFR 63.654 paragraph (g)(8). A Permittee may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph if the reports contain the information required by paragraphs (g)(1) through (g)(8) of 40 CFR 63.654.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in 40 CFR 63.654 paragraphs (g)(2) through (g)(5) except that information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source.

(2) A Permittee who elects to comply with 40 CFR 63.646 by using a fixed roof and an internal floating roof or by using an external floating roof converted to an internal floating roof shall submit the results of each inspection conducted in accordance with 40 CFR 63.120(a) of subpart G of this part in which a failure is detected in the control equipment.

(i) For vessels for which annual inspections are required under 40 CFR 63.120(a)(2)(i) or (a)(3)(ii) of Subpart G of this part, the specifications and requirements listed in 40 CFR 63.654 paragraphs (g)(2)(i)(A) through (g)(2)(i)(C) apply.

(A) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

(B) Except as provided in 40 CFR 63.654 paragraph (g)(2)(i)(C), each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(C) If an extension is utilized in accordance with 40 CFR 63.120(a)(4) of Subpart G of this part, the Permittee shall, in the next Periodic Report, identify the vessel; include the documentation specified in 40 CFR 63.120(a)(4) of Subpart G of this part; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(ii) For vessels for which inspections are required under 40 CFR 63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of Subpart G of this part (i.e., internal inspections), the specifications and requirements listed in 40 CFR 63.654 paragraphs (g)(2)(ii)(A) and (g)(2)(ii)(B) apply.

(A) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(3) A Permittee who elects to comply with 40 CFR 63.646 by using an external floating roof shall meet the periodic reporting requirements specified in 40 CFR 63.654 paragraphs (g)(3)(i) through (g)(3)(iii).

(i) The Permittee shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with 40 CFR 63.120(b) of Subpart G of this part in which the seal and seal gap requirements of 40 CFR 63.120(b)(3), (b)(4), (b)(5), or (b)(6) of Subpart G of this part are not met. This documentation shall include the information specified in 40 CFR 63.654 paragraphs (e)(3)(i)(A) through (e)(3)(i)(D).

(A) The date of the seal gap measurement.

(B) The raw data obtained in the seal gap measurement and the calculations described in 40 CFR 63.120(b)(3) and (b)(4) of Subpart G of this part.

(C) A description of any seal condition specified in 40 CFR 63.120(b)(5) or (b)(6) of Subpart G of this part that is not met.

(D) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(ii) If an extension is utilized in accordance with 40 CFR 63.120(b)(7)(ii) or (b)(8) of Subpart G of this part, the Permittee shall, in the next Periodic Report, identify the vessel; include the documentation specified in 40 CFR 63.120(b)(7)(ii) or (b)(8) of Subpart G of this part, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(iii) The Permittee shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by 40 CFR 63.120(b)(10) of Subpart G of this part. This documentation shall meet the specifications and requirements in 40 CFR 63.654 paragraphs (e)(3)(iii)(A) and (e)(3)(iii)(B).

(A) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(4) A Permittee who elects to comply with 40 CFR 63.646 by using an external floating roof converted to an internal floating roof shall comply with the periodic reporting requirements of paragraph (e)(2) of 40 CFR 63.654.

(5) A Permittee who elects to comply with 40 CFR 63.646 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in 40 CFR 63.654 paragraphs (g)(5)(i) through (g)(5)(iii).

(i) The Periodic Report shall include the information specified in 40 CFR 63.654 paragraphs (g)(5)(i)(A) and (g)(5)(i)(B) for those planned routine maintenance operations that would require the control device not to meet the requirements of 40 CFR 63.119(e)(1) or (e)(2) of Subpart G of this part, as applicable.

(A) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description shall include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(B) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description shall include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the requirements of 40 CFR 63.119 (e)(1) or (e)(2) of Subpart G of this part, as applicable, due to planned routine maintenance.

(ii) If a control device other than a flare is used, the Periodic Report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance Status report. The description shall include: Identification of the control device for which the measured parameters were outside of the established ranges, and causes for the measured parameters to be outside of the established ranges.

(iii) If a flare is used, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in 40 CFR 63.11(b) of Subpart A of this part and shall include: Identification of the flare that does not meet the general requirements specified in 40 CFR 63.11(b) of Subpart A of this part, and reasons the flare did not meet the general requirements specified in 40 CFR 63.11(b) of Subpart A of this part.

(6) For miscellaneous process vents for which continuous parameter monitors are required by this subpart, periods of excess emissions shall be identified in the Periodic Reports and shall be used to determine compliance with the emission standards.

(i) Period of excess emission means any of the following conditions:

(A) An operating day when the daily average value of a monitored parameter, except presence of a flare pilot flame, is outside the range specified in the Notification of Compliance Status report. Monitoring data recorded during periods of monitoring system breakdown, repairs, calibration checks and zero (low-level) and high-level adjustments shall not be used in computing daily average values of monitored parameters.

(B) An operating day when all pilot flames of a flare are absent.

(C) An operating day when monitoring data required to be recorded in paragraphs (g)(3) (i) and (ii) of this section are available for less than 75 percent of the operating hours.

(D) For data compression systems approved under paragraph (f)(5)(iii) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

(ii) For miscellaneous process vents, excess emissions shall be reported for the operating parameters specified in table 10 of this subpart unless other site-specific parameter(s) have been approved by the operating permit authority.

(iii) Periods of startup and shutdown that meet the definition of 40 CFR 63.641, and malfunction that meet the definition in 40 CFR 63.2 and periods of performance testing and monitoring system calibration shall not be considered periods of excess emissions. Malfunctions may include process unit, control device, or monitoring system malfunctions.

(7) If a performance test for determination of compliance for a new emission point subject to this subpart or for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic Report, the results of the performance test shall be included in the Periodic Report.

(i) Results of the performance test shall include the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) and the values of the monitored operating parameters.

(ii) The complete test report shall be maintained onsite.

(8) The Permittee of a source shall submit quarterly reports for all emission points included in an emissions average.

(i) The quarterly reports shall be submitted no later than 60 calendar days after the end of each quarter. The first report shall be submitted with the Notification of Compliance Status report no later than 150 days after the compliance date specified in 40 CFR 63.640.

(ii) The quarterly reports shall include:

(A) The information specified in this paragraph and in 40 CFR 63.654 paragraphs (g)(2) through (g)(7) for all storage vessels included in an emissions average;

(B) The information required to be reported by 40 CFR 63.428 (h)(1), (h)(2), and (h)(3) for each gasoline loading rack included in an emissions average, unless this information has already been submitted in a separate report;

(C) Any information pertaining to each wastewater stream included in an emissions average that the source is required to report under the Implementation Plan for the source;

(D) The credits and debits calculated each month during the quarter;

(E) A demonstration that debits calculated for the quarter are not more than 1.30 times the credits calculated for the quarter, as required under 40 CFR 63.652(e)(4);

(F) The values of any inputs to the credit and debit equations in 40 CFR 63.652 (g) and (h) that change from month to month during the quarter or that have changed since the previous quarter; and

(G) Any other information the source is required to report under the Implementation Plan for the source.

(f) Other reports shall be submitted as specified in Subpart A of this part and as follows:

(1) Reports of startup, shutdown, and malfunction required by 40 CFR 63.10(d)(5). Records and reports of startup, shutdown, and malfunction are not required if they pertain solely to Group 2 emission points, as defined in 40 CFR 63.641, that are not included in an emissions average. For purposes of this paragraph, startup and shutdown shall have the meaning defined in 40 CFR 63.641, and malfunction shall have the meaning defined in 40 CFR 63.2; and

(2) For storage vessels, notifications of inspections as specified in 40 CFR 63.654 paragraphs (h)(2)(i) and (h)(2)(ii);

(i) In order to afford the Administrator the opportunity to have an observer present, the Permittee shall notify the Administrator of the refilling of each Group 1 storage vessel that has been emptied and degassed.

(A) Except as provided in 40 CFR 63.654 paragraphs (h)(2)(i) (B) and (C), the Permittee shall notify the Administrator in writing at least 30 calendar days prior to filling or refilling of each storage vessel with organic HAP's to afford the Administrator the opportunity to inspect the storage vessel prior to refilling.

(B) Except as provided in 40 CFR 63.654 paragraph (h)(2)(i)(C), if the internal inspection required by 40 CFR 63.120(a)(2), 63.120(a)(3), or 63.120(b)(10) of Subpart G of this part is not planned and the Permittee could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP's, the Permittee shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. This notification, including the written documentation, may also be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

(C) The State or local permitting authority can waive the notification requirements of paragraphs (h)(2)(i)(A) and/or (h)(2)(i)(B) of 40 CFR 63.654 for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notification required by paragraph (h)(2)(i)(A) of 40 CFR 63.654, or sooner than 7 days after submitting the notification required by paragraph (h)(2)(i)(B) of 40 CFR 63.654 for all storage vessels, or for individual storage vessels on a case-by-case basis.

(ii) In order to afford the Administrator the opportunity to have an observer present, the Permittee of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by 40 CFR 63.120 (b)(1) or (b)(2) of Subpart G of this part. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

(3) For owners or operators of sources required to request approval for a nominal control efficiency for use in calculating credits for an emissions average, the information specified in 40 CFR 63.652(h).

(4) A Permittee may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in 40 CFR 63.654 paragraph (i).

(i) Requests shall be submitted with the Application for Approval of Construction or Reconstruction for new sources and no later than 18 months prior to the compliance date for existing sources. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal. Requests shall contain the information specified in 40 CFR 63.654 paragraphs (h)(5)(iii) through (h)(5)(iv), as applicable.

(ii) The provisions in 40 CFR 63.8(f)(5)(i) of Subpart A of this part shall govern the review and approval of requests.

(iii) A Permittee may request approval to use an automated data compression recording system that does not record monitored operating parameter values at a set frequency (for example, once every hour) but records all values that meet set criteria for variation from previously recorded values.

(A) The requested system shall be designed to:

(1) Measure the operating parameter value at least once every hour.

(2) Record at least 24 values each day during periods of operation.

(3) Record the date and time when monitors are turned off or on.

(4) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

(5) Compute daily average values of the monitored operating parameter based on recorded data.

(B) The request shall contain a description of the monitoring system and data compression recording system including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all criteria of paragraph (h)(5)(iii)(A) of 40 CFR 63.654.

(iv) A Permittee may request approval to use other alternative monitoring systems according to the procedures specified in 40 CFR 63.8(f) of Subpart A of this part.

(5) The Permittee shall submit the information specified in 40 CFR 63.654 paragraphs (h)(6)(i) through (h)(6)(iii), as applicable. For existing sources, this information shall be submitted in the initial Notification of Compliance Status report. For a new source, the information shall be submitted with the application for approval of construction or reconstruction required by 40 CFR 63.5(d) of Subpart A of this part. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units.

(ii) The determination of applicability of this subpart to any storage vessel for which use varies from year to year.

(iii) The determination of applicability of this subpart to any distillation unit for which use varies from year to year.

(g) Recordkeeping.

(1) The Permittee subject to the storage vessel provisions in 40 CFR 63.646 shall keep the records specified in 40 CFR 63.123 of Subpart G of this part except as specified in 40 CFR 63.654 paragraphs (i)(1)(i) through (i)(1)(iv).

(i) Records related to gaskets, slotted membranes, and sleeve seals are not required for storage vessels within existing sources.

(ii) All references to 40 CFR 63.122 in 40 CFR 63.123 of Subpart G of this part shall be replaced with 40 CFR 63.654(e).

(iii) All references to 40 CFR 63.150 in 40 CFR 63.123 of Subpart G of this part shall be replaced with 40 CFR 63.652.

(iv) If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

(2) Each Permittee required to report the results of performance tests under 40 CFR 63.654 paragraphs (f) and (g)(7) shall retain a record of all reported results as well as a complete test report, as described in 40 CFR 63.654 paragraph (f)(2)(ii) for each emission point tested.

(3) All other information required to be reported under 40 CFR 63.654 paragraphs (a) through (h) shall be retained for 5 years.

(h) To document compliance with Condition D.4.20, if the Permittee uses emissions averaging, the permittee shall keep records of all the required parameters listed in Condition D.4.20.

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

D.4.23 Recordkeeping Requirements [40CFR 60.696] [326 IAC 12]

Pursuant to 40 CFR 60.696, the Permittee shall comply with the following requirements:

(a) Each Permittee of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

(b)(1) For individual drain systems subject to Sec. 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

(2) For junction boxes subject to Sec. 60.692-2, the location, date, and corrective action shall be recorded for inspections required by Sec. 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(3) For sewer lines subject to Sec. Sec. 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by Sec. Sec. 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

(c) For oil-water separators subject to Sec. 60.692-3, the location, date, and corrective action shall be recorded for inspections required by by Sec. 60.692-3(a) when a problem is identified that could result in VOC emissions.

(d) For closed vent systems subject to Sec. 60.692-5 and completely closed drain systems subject to Sec. 60.693-1, the location, date, and corrective action shall be recorded for inspections required by Sec. 60.692-5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

(e)(1) If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.
(2) The reason for the delay as specified in Sec. 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.
(3) The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.
(4) The date of successful repair or corrective action shall be recorded.

(f)(1) A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.
(2) The following information pertaining to the design specifications shall be kept.
(i) Detailed schematics, and piping and instrumentation diagrams.
(ii) The dates and descriptions of any changes in the design specifications.
(3) The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.
(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 oC (1,500 oF) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.
(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.
(iii) Periods when the closed vent systems and control devices required in Sec. 60.692 are not operated as designed, including periods when a flare pilot does not have a flame shall be recorded and kept for 2 years after the information is recorded.
(iv) Dates of startup and shutdown of the closed vent system and control devices required in Sec. 60.692 shall be recorded and kept for 2 years after the information is recorded.
(v) The dates of each measurement of detectable emissions required in Sec. Sec. 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.
(vi) The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.

(vii) The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.

(viii) Each Permittee of an affected facility that uses a thermal incinerator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 oC (50 oF) below the design combustion zone temperature, and shall keep such records for 2 years after the information is recorded.

(ix) Each Permittee of an affected facility that uses a catalytic incinerator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 oC (50 oF) below the design gas stream temperature, and records of all 3-hour periods during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference, and shall keep such records for 2 years after the information is recorded.

(x) Each Permittee of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(A) Each Permittee of an affected facility that uses a carbon adsorber which is regenerated directly onsite shall maintain continuous records of the volatile organic compound concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(B) If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

(g) If the Permittee elects to install a tightly sealed cap or plug over a drain that is out of active service, the owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which indicate the location of such drains.

(h) For stormwater sewer systems subject to the exclusion in Sec. 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

(i) For ancillary equipment subject to the exclusion in Sec. 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonsrate that the ancillary equipment does not come in contact with or store oily wastewater.

(j) For non-contact cooling water systems subject to the exclusion in Sec. 60.692-1(d)(3), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

(k) For oil-water separators subject to Sec. 60.693-2, the location, date, and corrective action shall be recorded for inspections required by Sec. Sec. 60.693-2(a)(1)(iii)(A) and (B), and shall be maintained for the time period specified in paragraphs (k)(1) and (2) of this section.

(1) For inspections required by Sec. 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.

(2) For inspections required by Sec. 60.693-2(a)(1)(iii)(B), two years after the information is recorded.

D.4.24 Reporting Requirements [40CFR 60.698] [326 IAC 12]

Pursuant to 40 CFR 60.698, the Permittee shall comply with the following requirements:

(a) The Permittee electing to comply with the provisions of Sec. 60.693 shall notify the Administrator of the alternative standard selected in the report required in Sec. 60.7.

(b)(1) Each Permittee of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

(2) Each Permittee of an affected facility that uses a flare shall submit to the Administrator within 60 days after initial startup, as required under Sec. 60.8(a), a report of the results of the performance test required in Sec. 60.696(c).

(c) A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to OAQ, IDEM.

(d) As applicable, a report shall be submitted semiannually to the Administrator that indicates:

(1) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal incinerator, as measured by the temperature monitoring device, is more than 28 [deg]C (50 [deg]F) below the design combustion zone temperature,

(2) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic incinerator, as measured by the temperature monitoring device, is more than 28 [deg]C (50 [deg]F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference, or,

(3) Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

(i) Each 3-hour period of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases from a carbon adsorber which is regenerated directly onsite is more than 20 percent greater than the design exhaust gas concentration level or reading.

(ii) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in Sec. 60.695(a)(3)(ii).

(e) If compliance with the provisions of this subpart is delayed pursuant to Sec. 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(a) one (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 and exhausting to stack 118;
(b) one (1) crude heater equipped with the Low-NOx burner, with a maximum heat input rate of 131 million British Thermal Units per hour (mmBtu/hr) of No. 6 residual oil and process gas, identified as C-II, exhausting to stack 1;
(c) one (1) unifiner heater, with a maximum heat input rate of 20 mmBtu/hr of process gas, identified as H-H5 and exhausting to stack 2;
(d) one (1) cycle oil heater, with a maximum heat input rate of 10 mmBtu/hr of process gas, identified as H-H2 and exhausting to stack 3;
(e) one (1) naphtha splitter heater, with a maximum heat input rate of 12.2 mmBtu/hr of process gas, identified as H-H3 and exhausting to stack 4;
(f) one (1) vacuum heater, with a maximum heat input rate of 14.1 mmBtu/hr of process gas, identified as V-IV and exhausting to stack 5;
(g) one (1) old Platformer heater, with a maximum heat input rate of 29 mmBtu/hr of process gas, identified as P-H1 and exhausting to stack 6;
(h) one (1) alkylation unit heater, with a maximum heat input rate of 13.2 mmBtu/hr of process gas, identified as A-H1 and exhausting to stack 7;
(i) one (1) auxiliary crude heater, with a maximum heat input rate of 10.1 mmBtu/hr of process gas, identified as C-I and exhausting to stack 11;
(j) one (1) platformer stabilizer reb, with a maximum heat input rate of 5.92 mmBtu/hr of process gas, identified as P-H2 and exhausting to stack 12;
(k) one (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;
(l) one (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;
(m) one (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;
(n) one (1) vacuum heater husky, with a maximum heat input rate of 6.27 mmBtu/hr of No. 6 residual oil and process gas, identified as VIII and exhausting to stack 64.
(o) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no sour water stripper overhead off-gas combustion), installed in 1945 and exhausting to stack 9.

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

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

D.5.1 Particulate Matter (PM)

Pursuant to 326 IAC 6-2-3 (Particulate Matter Emission Limitations for Sources of Indirect Heating, the PM emissions from boilers B1, B2 and B3 shall be limited to 0.40, 0.25 and 0.40 pounds per MMBtu heat input, respectively.

This limitation is based on the following equation:

$$P_T = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where: C = maximum ground level concentration (50 µg/m3, for a period not to exceed 60 min.)
Pt = maximum allowable particulate matter (PM) emitted per MMBtu heat input
Q = total source max. indirect heater input

N = Number of stacks in fuel burning operation.

a = plume rise factor (0.67, for Q < 1,000)

h = Stack height in feet. If a number of stacks of different heights exist, the average stack height to represent "N" stacks shall be calculated by weighing each stack height with its particulate matter emission rate as follows:

$$h = \frac{\sum_{i=1}^{N} H_i \times pa_i \times Q}{\sum_{i=1}^{N} pa_i \times Q}$$

Where: pa = the actual controlled emission rate in lb/mmBtu using the emission factor from AP-42 or stack test data.

D.5.2 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the emission units C-II, boilers Nos. 1, 2 and 3, V-IV, A-HI, H101, and V-III, when burning No. 6 residual fuel oil, shall not exceed 1.6 pounds per MMBtu heat input. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a thirty (30) day rolling weighted average.

D.5.3 No. 6 Fuel Usage [326 IAC 2-2]

The input of No. 6 fuel oil to the three boilers B1, B2, and B3, based on a maximum fuel oil sulfur content of 0.8 percent shall be limited, to 3,214.92 thousand gallons per twelve (12) consecutive month period with compliance determined at the end of each month. This usage limit is required to limit the PM10 emissions from the boilers to less than 14.49 tons per twelve (12) consecutive month period. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

D.5.4 General Provisions Relating to NESHAP [326 IAC 20-1][40 CFR Part 63, Subpart A]

The provisions of 40 CFR 63 Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the affected sources, as designated by 40 CFR 63.7506(b). The Permittee must comply with these requirements on and after the effective date of 40 CFR 63, Subpart DDDDD.

D.5.5 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]

(a) The affected sources are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters, (40 CFR 63, Subpart DDDDD), as of the effective date of 40 CFR 63, Subpart DDDDD. Pursuant to this rule, the Permittee must comply with 40 CFR 63, Subpart DDDDD on and after three years after September 13, 2004, the effective date of 40 CFR 63, Subpart DDDDD.

(b) The following emissions units comprise the affected source for the large liquid fuel subcategory:
(1) One (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8.
(2) One (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13.
(3) One (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14.

(c) The definitions of 40 CFR 63, Subpart DDDDD at 40 CFR 63.7575 are applicable to the affected source(s).

Compliance Determination Requirements

D.5.6 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition D.5.2 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 1.6 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.5.7 Visible Emissions Notations

(a) Visible emission notations of the boiler stacks (B1, B2 and B3) exhaust shall be performed once per shift during normal daylight operations when exhausting to the atmosphere and while combusting fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or 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) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a violation of this permit.

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

D.5.8 Record Keeping Requirements

(a) To document compliance with Conditions D.5.2, the Permittee shall maintain records in accordance with (1) through (6) below.

(1) Calendar dates covered in the compliance determination period;
(2) Actual No. 6 residual fuel oil usage per month since last compliance determination period and equivalent SO_2 emissions;
(3) A certification, signed by the Permittee, that the records of the fuel supplier certifications represent all of the fuel combusted during the period; and

If the fuel supplier certification is used to demonstrate compliance 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.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document compliance with Condition D.5.4, the Permittee shall maintain records of visible emission notations of the three boiler stacks (B1, B2 and B3) once per shift.

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

D.5.9 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters - Notification Requirements [40 CFR 63, Subpart DDDDD]

(a) Pursuant to 40 CFR 63.7545(a) and 40 CFR 63.7506(b), the Permittee shall submit an Initial Notification containing the information specified in 40 CFR 63.9(b)(2) not later than 120 days after the effective date of 40 CFR 63, Subpart DDDDD as required by 40 CFR 63.7545(b).

(b) The notification required by paragraph (a) shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

and

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

The notification requires the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Mailing Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-7882-00003
Facility: Boilers B1, B2, and B3
Parameter: No. 6 Fuel Oil Usage
Limit: The input of No. 6 fuel oil to the three boilers B1, B2, and B3, based on a maximum fuel oil sulfur content of 0.8 percent shall be limited, to 3,214.92 thousand gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

YEAR:

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

☐ No deviation occurred in this quarter.

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

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

Attach a signed certification to complete this report.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Significant Source Modification and Significant Permit Modification to a Part 70 Operating Permit

Source Background and Description

Source Name:	Countrymark Cooperative, LLP
Source Location:	1200 Refinery Road, Mount Vernon, Indiana 47620
County:	Posey
SIC Code:	2911
Operation Permit No.:	T129-7882-00003
Operation Permit Issuance Date:	July 21, 2003
Source Modification No.:	129-18672-00003
Permit Modification No.:	129-20112-00003
Permit Reviewer:	Adeel Yousuf/EVP

The Office of Air Quality (OAQ) has reviewed a Part 70 permit modification application from Countrymark Cooperative, LLP relating to the construction and the operation of the distillate hydrotreating unit, gas treating system, and a new storage tank at its Mount Vernon Refinery as part of the Distillate Desulfurization Project. The Distillate Desulfurization Project will enable the refinery to produce a low sulfur diesel product and provide a means for the removal of most of the hydrogen sulfide from the refinery fuel gas burned in the new and existing heaters and boilers.

History

On March 15, 2004, Countrymark Cooperative, LLP submitted an application to the OAQ requesting to construct a Distillate Desulfurization Unit consisting of a new distillate hydrotreating unit, a new gas treating system, a new sour water storage tank, and one new heavy oil storage tank to replace an existing heavy oil tank. The new gas treating system includes an amine unit, a Claus sulfur recovery unit, tail gas treating unit, and small flare. Significant portions of the existing sour water stripper unit will also be replaced. Countrymark Cooperative, LLP was issued a Part 70 permit (T129-7882-00003) on July 21, 2003.

Explanation of Modification Requested

This significant source modification and significant permit modification consists of the following changes to the source:

(a) Construction of Distillate Hydrotreater operation consisting of:
- (1) Hydrotreater Unit Reactor charge heater; and
- (2) Hydrotreater Unit Stabilizer reboiler heater.

(b) Construction of Sulfur Recovery Unit and Tail Gas Treating Unit (TGTU) consisting of:
- (1) TGTU incinerator;
- (2) TGTU Incinerator burner;
- (3) Claus Unit Startup burner; and
- (4) Sour Flare.

(c) Construction of one new storage tank to store sour water.

(d) Addition of controls on the oil/water separator unit.

(e) Construction of new wastewater drains and Modifications to existing drains.

(f) Conversion of existing Tank 46 service from unleaded gasoline to low sulfur diesel product storage and cleaning.

(g) Conversion of existing Tank 34 from light cycle oil (LCO) rundown to low sulfur distillate rundown service.

(h) Conversion of Tank 35 from FCC Cat Gasoline/Isomerate rundown to low sulfur distillate rundown service.

(i) Modification to existing FCCU Pre-heater (H-101) where this unit will no longer combust H_2S from the sour Water Stripper system resulting in decrease of SO2 emissions by 33.48 tons per year.

(k) Modification to the Crude Heater C-II where this unit will be equipped with the Low NOx burner resulting in decrease of NOx by 48.44 tons per year.

(l) Increase in No. 6 fuel oil usage for the three (3) boilers (B1, B2, and B3) resulting in increase in emissions.

New Emission Units and Pollution Control Equipment

The source consists of the following new emission units and pollution control devices:

(a) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (to be constructed in 2005).

(b) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 (to be constructed in 2005).

(c) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:
   (1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).
   (2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.
   (3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).

Permitted Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units and pollution control devices:

(d) One (1) vertical fixed roof tank, identified as Tank No. 22A, with a capacity of 1,050,000 gallons and a maximum withdrawal rate of 84,000 gallons per hour of hydrocarbon with vapor pressure of No. 2 fuel oil or less and exhausting to stack 120 (to be constructed in 2005).

Note: This unit (Tank No. 22A) has already been permitted to construct and operate under the Minor Source Modification No.(129-18135) and Significant Permit Modification No.129-(17940) issued on November 17 and 24, 2003, respectively. Since this unit is being constructed in the same contemporaneous period as the rest of the Distillate Desulfurization Project it is being included in this modification.

(e) Addition of covers for VOC control on two (2) sets of Oil/water Separators, identified as 071 (to be installed in 2005).

(f) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of:
(1) pipeline Valves - Gas, identified as 090;
(2) pipeline Valves - Light Liquid, identified as 091;
(3) pipeline Valves - Heavy Liquid, identified as 092;
(4) pipeline Valves - Hydrogen, identified as 093;
(5) open Ended Valves, identified as 094;
(6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(7) flanges, identified as 095;
(8) pump Seals Light Liquid, identified as 096;
(9) pump Seals Heavy Liquid, identified as 097;
(10) compressor Seals - Gas, identified as 098;
(11) compressor Seals - Heavy Liquid, identified as 099;
(12) drains, identified as 100;
(13) vessel Relief Valves, identified as 101; and
(14) cooling Towers, identified as 119.

(g) One (1) internal floating roof tank, identified as Tank No. 125 (710-T-101), with a capacity of 157,000 gallons and a maximum withdrawal rate of 6,000 gallons per hour of hydrocarbon with vapor pressure of No. 2 fuel oil or less and exhausting to stack 015 (to be constructed in 2005).

(h) Installation of Low-NOx burners on one existing (1) Crude heater, identified as C-II with a maximum heat input rate of 131 mmBtu/hr, combusting refinery fuel gas and No. 6 fuel oil (to be installed in 2005).

(i) One (1) existing Fluid Catalytic Cracking Unit (FCCU) preheater, identified as H-101 with a maximum heat input rate of 18.1 mmBtu/hr, continuing to combust refinery fuel gas but there will be no H_2S combustion in this unit.

(j) Increase in No. 6 fuel oil usage for the three (3) existing boilers (B1, B2 and B3), each with a maximum heat input rate of 52, 65, and 52 mmBtu/hr respectively. This increase in emissions is an indirect result of the Distillate Desulfurization Project.

Note: Existing boilers B1, B2, and B3 at the refinery combust refinery fuel gas as a primary fuel, however, the emission units associated with the Distillate Desulfurization Project will consume some of the refinery fuel gas, therefore, resulting in fuel imbalance for the three boilers. In order to compensate for this fuel imbalance, Countrymark will be burning more natural gas and/or No. 6 fuel oil. Although the source is allowed to combust No. 6 fuel oil in the three boilers in unlimited quantities as permitted in the original Title V permit, the increase in emission is an indirect result of the Distillate Desulfurization Project; therefore the emissions are included in the net emission analysis and the evaluation of PSD significant levels as part of the project.

Insignificant Activities for the Modification

The modification also consists of the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Combustion source flame safety purging on startup.

(b) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume.

(c) Heat exchanger cleaning and repair.

(d) Process vessel degassing and cleaning to prepare for internal repairs.

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

(f) Purging of gas lines and vessels that is related to routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process.

(g) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment.

(h) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

(i) On-site fire and emergency response training approved by the department.

(j) Purge double block and bleed valves.

(k) Filter or coalescer media changeout.

(l) Activities or categories not previously identified with emissions less than or equal to insignificant thresholds:
   (1) Sulfur loading operation consisting of eductor system used to remove H_2S and SO_2 from the sulfur pit and these emissions conveyed to the TGTU incinerator for destruction.
   (2) One (1) fixed roof cone tank, identified as 125-6, with a maximum amine and condensate storage capacity of 9,450 gallons.
   (3) One (1) fixed roof cone tank, identified as 125-7, with a maximum amine and condensate storage capacity of 1,200 gallons.
   (4) One time cleaning of Tank 46 as a result of conversion of the service from unleaded gasoline to sulfur diesel product storage.

Unpermitted Emission Units and Pollution Control Equipment

There are no unpermitted facilities operating at this source during this review process.

Existing Approvals

The source was issued a Part 70 Operating Permit (T129-7882-00003) on July 21, 2003. The source has since received the following:

(a) First Minor Source Modification No.: 129-18135, issued on November 17, 2003.

(b) First Significant Permit Modification No.: 129-17940, issued on November 24, 2003.

Enforcement Issue

There are no enforcement actions pending.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)
122	Hydrotreater Unit Reactor Charge Heater	115	2.96	9,070	683
123	Hydrotreater Unit Stabilizer Reboiler Heater	123	3.125	9,970	704
124-1	Claus Unit Startup Burner	132	1.33	48,000	1200
124-3	TGTU Incinerator	132	1.33	48,000	1200
124-4	Sour Flare	132	TBD	TBD	TBD
124-2	TGTU Incinerator Burner	132	1.33	48,000	1200

Recommendation

The staff recommends to the Commissioner that the Significant Source Modification and Significant Permit Modification be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on March 14, 2003. Additional information was received on August 4, 2004 and September 10, 2004.

Emission Calculations

See Appendix A of this document for detailed emissions calculations (Seventeen (17) pages).

Potential To Emit Before Controls (Modification)

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA."

Pollutant	Potential To Emit (tons/year)
PM	16.37
PM-10	14.49
SO_2	70.65
VOC	10.04
CO	19.70
NO_x	75.57

HAP's	Potential To Emit (tons/year)
Hexane	3.715
Others	0.285
TOTAL	4.00

Justification for Modification

The Part 70 operating permit is being modified through both a Part 70 Significant Source Modification and Significant Permit Modification. These modifications are being performed based on the following justification:

(a) The potential to emit (as defined in 326 IAC 2-1.1-1(16)) of SO_2 and NOx are each equal to or greater than 25 tons per year. Therefore, this modification is being performed pursuant to 326 IAC 2-7-10.5(f)(4).

(b) The proposed operating conditions shall be incorporated into the Part 70 Operating Permit as a Significant Permit Modification (No. 129-20112-00003) in accordance with 326 IAC 2-7-12(d). The Significant Permit Modification will give the source approval to operate the proposed emission units.

County Attainment Status

The source is located in Posey County.

Pollutant	Status
PM-10	Attainment
SO_2	Attainment
NO_2	Attainment
1-hour Ozone	Attainment
8-hour Ozone	Attainment
CO	Attainment
Lead	Attainment

(a) Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC emissions and NOx are considered when evaluating the rule applicability relating to ozone. Posey County has been designated as attainment or unclassifiable for ozone. Therefore, VOC emissions and NOx were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability for the source section.

(b) Posey County has been classified as attainment or unclassifiable in Indiana for all the criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability for the source section.

(e) Fugitive Emissions
Since this type of operation is one of the 28 listed source categories under 326 IAC 2-2, the fugitive particulate matter (PM) and volatile organic compound (VOC) emissions are counted toward determination of PSD and Emission Offset applicability.

Source Status

Existing Source PSD Definition (emissions after controls, based upon 8760 hours of operation per year at rated capacity and/or as otherwise limited):

Pollutant	Emissions (tons/year)
PM	not reported
PM-10	44.0
SO_2	643.0
VOC	668.0
CO	7,919
NOx	453.0

(a) This existing source is a major stationary source because an attainment regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the 28 listed source categories.

(b) These emissions are based upon Indiana Air Emissions Summary Data for 2001.

Potential to Emit of Modification After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the modified emission units after controls.

	Potential to Emit (tons/year) of Modification After Issuance							
Process/facility	PM	PM10	SO_2	VOC	CO	NO_X	Single HAP	Total HAPs
Hydrotreater Unit Reactor Charge Heater (122)	0.74	0.74	2.79	0.54	8.22	3.37	0.176 (Hexane)	0.183
Hydrotreater Unit Stabilizer Reboiler Heat (123)	0.77	0.77	2.89	0.56	8.52	3.49	0.183 (Hexane)	0.191
Claus Unit Startup Burner (124-1)	0.05	0.05	0.00	0.04	0.56	0.67	0.012 (Hexane)	0.01
TGTU Incinerator Burner (124-2)	0.05	0.05	0.19	0.04	0.55	0.66	0.012 (Hexane)	0.01
TGTU Incinerator Process Emissions (124-3)	0.00	0.00	11.44	0.00	0.00	0.00	0.00	0.00
Sour Flare Pilot plus continuous amine-treated gas streams (124-4)	0.03	0.03	0.04	0.02	0.33	0.40	0.007 (Hexane)	0.01
Storage Tank 710-T-101	0.00	0.00	0.00	0.172	0.00	0.00	0.005 (Hexane)	0.011
Cleaning of Tank 46 [a]	0.00	0.00	0.00	7.40	0.00	0.00	0.052 (Hexane)	0.141
Fugitive Emissions (Valves, Pumps, Flanges, etc.) [b]	0.00	0.00	0.00	1.23	0.00	0.00	0.025 (Hexane)	0.06
Total Modification Emissions	1.65	1.65	17.35	10.00	18.19	8.59	0.472 (Hexane)	0.61
Contemporaneous Increases (Increase in No. 6 fuel oil usage in Boilers B1, B2, and B3)	14.72	12.84	53.30	0.04	1.51	66.98	3.243 (Hexane)	3.39
Contemporaneous Decreases								
Modification in FCCU Pre-Heater (H-101) fuel usage	0.00	0.00	-33.48 [c]	0.00	0.00	0.00	0.00	0.00
Installation of Low-NOx burner on Crude Heater C-II	0.00	0.00	0.00	0.00	0.00	-48.44	0.00	0.00
Oil Water Separator Control	0.00	0.00	0.00	-280.28	0.00	0.00	-1.656 (Hexane)	-4.496
Net Emissions Increase	16.37	14.49	37.17	-270.24	19.70	27.13	2.059 (Hexane)	-0.496
PSD Threshold Level	25	15	40	40	40	40	N/A	N/A

a. Cleaning of Tank 46 is a one time operation which is being performed due to the conversion of tank service from unleaded gasoline to low sulfur diesel product storage.
b. Fugitive emissions from Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit and TGTU units.
c. Decrease in SO_2 emissions due to elimination of H_2S combustion. Only refinery gas will be combusted in this unit.

This modification to an existing major stationary source is not major because the emission increase of the modification is less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Federal Rule Applicability

(a) The requirements of 40 CFR Part 64, Compliance Assurance Monitoring, are not applicable to this modification. Such requirements apply to a pollutant-specific emissions unit (PSEU), as defined in 40 CFR 64.1, at a major source that is required to obtain a Part 70 or 71 permit if the PSEU meets the following criteria:

(1) the unit is subject to an emission limitation or standard for an applicable regulated air pollutant,

(2) the unit uses a control device as defined in 40 CFR 64.1 to comply with that emission limitation or standard, and

(3) the unit has a potential to emit (PTE) before controls equal to or greater than 100 percent of the amount (tons per year) of the pollutant required for a source to classified as a Part 70 major source.

This source was issued Part 70 Permit No. T129-7882-00003 on July 24, 2003. For this modification, no unit has potential pre-control emissions of a regulated air pollutant that are equal or greater than 100 tons per year. Therefore, the requirements of 40 CFR Part 64, Compliance Assurance Monitoring, are not applicable to this modification.

(b) Storage tank identified as 22A (which is already permitted to construct and operate under Minor Source Modification No. 129-18135-00003 and Significant Permit Modification No. 129-17940-00003, issued on November 17, 2004 and November 24, 2004, respectively) is subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.110, Subpart Kb) where construction, reconstruction, or modification commenced after July 23, 1984. Tank 22A has a storage capacity of greater than 151 cubic meters (m^3) (39,889 gallons) and stores jet kerosene and diesel fuel, with a maximum true vapor pressure less than 3.5 kPa, therefore, pursuant to 40 CFR 60.110b(c), this tank is exempt from all other provisions of this Subpart except 60.116b, which requires that permanent records be maintained showing dimensions and an analysis of the capacity of the tank.

(c) Storage tank identified as 125 (710T-101) is subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.110, Subpart Kb) where construction, reconstruction, or modification commenced after July 23, 1984. Tank 710T-101 has a storage capacity of greater than 151 cubic meters (m^3) (39,889 gallons) and stores sour water, with a maximum true vapor pressure less than 3.5 kPa, therefore, pursuant to 40 CFR 60.110b(c), this tank is exempt from all other provisions of this Subpart except 60.116b, which requires that permanent records be maintained showing dimensions and an analysis of the capacity of the tank.

(d) (I) The requirements of the New Source Performance Standard, 326 IAC 12, (40 CFR 60.100, Subpart J – Standards of Performance for Petroleum Refineries) are not included in the permit for the FCCU Pre-heater H-101 and Crude Heater C-II. Construction of these units commenced prior to June 11, 1973. The modification to the FCCU Pre-heater H-101 involves a change in fuel combustion where this unit will no longer combust H_2S gas, therefore resulting in a decrease in SO_2 emissions. The modification to the Crude Heater C-II involves an installation of Low-NOx burner which will result in a decrease in NOx emissions. The modification to these units does not fit the definition of “modification” as listed under 40 CFR Part 60.2 (Definitions) as there is no increase in emissions. Therefore, the requirements of the rule are not included in this permit.

(II) The requirements of the New Source Performance Standard, 326 IAC 12, (40 CFR 60.100, Subpart J – Standards of Performance for Petroleum Refineries) are not included in the permit for the new Sulfur Recovery Unit (124) because the Claus sulfur recovery unit has processing capacity of 20 tons per day or less, and therefore exempt from the requirements of NSPS, Subpart J.

(III) The Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2), and Sour Flare (124-4), all combusting refinery fuel gas are subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60.100, Subpart J - Standards of Performance for Petroleum Refineries), because these units combust refinery fuel gas and commenced construction after the rule applicability date of June 11, 1973.

(a) 40 CFR 60.100 Applicability, designation of affected facility, and reconstruction.

(i) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(ii) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (i) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (i) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this subpart except as provided under paragraphs (iii) and (iv) of this section.

(iii) Any fluid catalytic cracking unit catalyst regenerator under paragraph (ii) of this section which commences construction or modification on or before January 17, 1984, is exempted from 40 CFR 60.104(b).

(iv) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction or modification on or before January 17, 1984, is exempt from this subpart.

(v) For purposes of this subpart, under 40 CFR 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, "commenced" means that the Permittee undertaken a continuous program of component replacement or that the Permittee has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

(b) 40 CFR 60.104 Standards for sulfur oxides.

Each Permittee that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by 40 CFR 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

No Permittee subject to the provisions of this subpart shall:

(i) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(c) 40 CFR 60.105 Monitoring of emissions and operations.

(A) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fuel gas combustion devices subject to 40 CFR 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of 40 CFR 60.105. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO2 and 25 percent oxygen (O2).

(ii) The SO_2 monitoring level equivalent to the H_2S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the S2 emissions into the atmosphere from each of the combustion devices.

(2) In place of the SO2 monitor in paragraph (a)(3) of 40 CFR 60.105, an instrument for continuously monitoring and recording the concentration (dry basis) of H2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H2S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned.

(iii) The performance evaluations for this H2S monitor under Sec. 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(3) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to 40 CFR 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.
(i) The span values for this monitor are 500 ppm O2 and 25 percent O2.
(ii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(4) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105 are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(5) The Permittee shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105.
(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the 40 CFR 60.13(e) performance evaluation.
(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

Testing methods and procedures for this subpart are required under 40 CFR 60.106.

The refinery fuel gas for the above listed emission units contains less than 230 mg/dscm (0.10 gr/dscf) of H2S, therefore the operation of these units is in compliance with the requirement of Subpart J.

(e) Equipment associated with the Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit and TGTU are subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60.590, Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries), because they are being constructed after the rule applicability date of January 4, 1983 and are located at a petroleum refinery.

(1) 40 CFR 60.590 Applicability and designation of affected facility.
(i) Applicability and designation of affected facility.
(A) The provisions of this subpart apply to affected facilities in petroleum refineries.
(B) A compressor is an affected facility.
(C) The group of all the equipment (defined in 40 CFR 60.591) within a process unit is an affected facility.
(ii) Any affected facility under paragraph (i) of this section that commences construction or modification after January 4, 1983, is subject to the requirements of this subpart.
(iii) Addition or replacement of equipment (defined in 40 CFR 60.591) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(iv) Facilities subject to Subpart VV or Subpart KKK of 40 CFR part 60 are excluded from this subpart.

(2) 40 CFR 60.592 Standards.

(i) Each Permittee subject to the provisions of this subpart shall comply with the requirements of 40 CFR 60.482-1 to 40 CFR 60.482-10 as soon as practicable, but no later than 180 days after initial startup.

(ii) A Permittee may elect to comply with the requirements of 40 CFR 60.483-1 and 40 CFR 60.483-2.

(iii) A Permittee may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the Permittee shall comply with requirements of 40 CFR 60.484.

(iv) Each Permittee subject to the provisions of this subpart shall comply with the provisions of 40 CFR 60.485 except as provided in 40 CFR 60.593.

(v) Each Permittee subject to the provisions of this subpart shall comply with the provisions of 40 CFR 60.486 and 40 CFR 60.487.

(3) 40 CFR 60.593 Exceptions.

(i) Each Permittee subject to the provisions of this subpart may comply with the following exceptions to the provisions of Subpart VV.

(ii) (A) Compressors in hydrogen service are exempt from the requirements of 40 CFR 60.592 if a Permittee demonstrates that a compressor is in hydrogen service.

(B) Each compressor is presumed not be in hydrogen service unless a Permittee demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E-260, E-168, or E-169 (incorporated by reference as specified in 40 CFR 60.17) shall be used.

(C) (aa) The Permittee may use engineering judgment rather than procedures in paragraph (ii)(B) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When the Permittee and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (ii)(B) shall be used to resolve the disagreement.

(bb) If the Permittee determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (ii)(B).

(iii) Any existing reciprocating compressor that becomes an affected facility under provisions of 40 CFR 60.14 or 40 CFR 60.15 is exempt from 40 CFR 60.482 (a), (b), (c), (d), (e), and (h) provided the Permittee demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR 60.482 (a), (b), (c), (d), (e), and (h).

(iv) The Permittee may use the following provision in addition to 40 CFR 60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150oC as determined by ASTM Method D-86 (incorporated by reference as specified in 40 CFR 60.18).

(v) Pumps in light liquid service and valves in gas/vapor and light liquid service within a procesic compounds of usually high molecular weight that consist of many repeated links, each link being a relatively light and simple molecule.

The source will comply with the requirements of 40 CFR 60.590, Subpart GGG by monitoring fugitive VOC emissions from the affected facilities, following the procedures outlined in 40 CFR 60.590 through 60.593.

(f) The addition of controls to Oil/Water Separator and addition of new wastewater drains and modifications to existing drains are all subject to the requirements of 40 CFR Part 60 Subpart QQQ - Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems (326 IAC 12) because these facilities are located at a petroleum refinery and are being constructed or modified after the rule applicability date of May 4, 1987. These facilities must comply with the standards in 40 CFR 60.692-1, 60.692-2, 60.692-3, 60.692-4, 60.692-5, 60.692-6, and 60.692-7; the monitoring requirements in 40 CFR 60.695; the performance test methods and procedures 40 CFR 60.696; the record keeping requirements in 40 CFR 60.697; and the reporting requirements in 40 CFR 60.698. These requirements are as follows:

(I) 40 CFR 60.692-1 Standards – General

(a) Pursuant to 40 CFR 60.692-1(a), the Permittee shall comply with the requirements of 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2 for all facilities subject to the provisions of 40 CFR 60, Subpart QQQ as provided in 40 CFR 60.690, except during periods of startup, shutdown, or malfunction.

(b) Compliance with 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR 60.696.

(c) Permission to use alternative means of emission limitation to meet the requirements of 40 CFR 60.692-2 through 60.692-4 may be granted as provided in 40 CFR 60.694.

(d) Pursuant to 40 CFR 60.692-1(d), the following units are not subject to the control requirements of 40 CFR 60, Subpart QQQ:

(1) Stormwater sewer systems;

(2) Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater; and

(3) Non-contact cooling water systems.

The Permittee shall demonstrate compliance with the exclusions in paragraphs 40 CFR 60.692-1 (d)(1), (2), and (3) of this section as provided in 40 CFR 60.697(h), (i), and (j).

(e) The definitions in 40 CFR 60, Subpart QQQ, Section 60.691 are applicable to the Permittee.

(II) 40 CFR 60.692-2 Standards: Individual Drain Systems

Pursuant to 40 CFR 60.692-2, the Permittee shall comply with the following requirements:

(a)(1) Each drain shall be equipped with water seal controls.

(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.
(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.
(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.
(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in Sec. 60.692-6.

(b)(1) Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
(2) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
(3) Junction boxes shall be visually inspected initially and semiannually hereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.
(4) If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in Sec. 60.692-6.

(c)(1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.
(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.
(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in Sec. 60.692-6.

(d) Except as provided in paragraph (e) of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section.

(e) Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

(III) 40 CFR 60.692-3 Standards: Oil-water separators.
Pursuant to 40 CFR 60.692-3, the Permittee shall comply with the following requirements:

(a) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in 40 CFR 60.693-2.

(1) The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.
(2) The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.
(3) If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.
(4) Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.
(5) When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in Sec. 60.692-6.

(b) Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph (a) of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of Sec. 60.692-5, except as provided in paragraph (c) of this section or in Sec. 60.693-2.

(c)(1) Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of paragraph (b) of this section, but shall meet the requirements of paragraph (a) of this section, or may elect to comply with paragraph (c)(2) of this section.
(2) The owner or operator may elect to comply with the requirements of paragraph (a) of this section for the existing fixed roof covering a portion of the separator tank and comply with the requirements for floating roofs in Sec. 60.693-2 for the remainder of the separator tank..

(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in Secs. 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

(e) Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph (a) of this section.

(f) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph (a) of this section, and not paragraph (b) of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

(IV) 40 CFR 60.692-4 Standards: Aggregate facility.

Pursuant to 40 CFR 60.692-4, a new, modified, or reconstructed aggregate facility shall comply with the requirements of40 CFR 60.692-2 and 60.692-3.

(V) 40 CFR 60.692-5 Standards: Closed vent systems and control devices.

Pursuant to 40 CFR 60.692-5, the Permittee shall comply with the following requirements:

(a) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 deg.C (1,500 deg.F).
(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.
(c) Flares used to comply with this subpart shall comply with the requirements of 40 CFR 60.18.
(d) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.
(e)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in 40 CFR 60.696.
(2) Closed vent systems shall be purged to direct vapor to the control evice.
(3) A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.
(4) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.
(5) When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in 40 CFR 60.692-6.

(VI) 40 CFR 60.692-6 Standards: Delay of repair.

Pursuant to 40 CFR 60.692-6, delay of repair of facilities that are subject to 40 CFR 60, Subpart QQQ shall be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

(VII) 40 CFR 60.692-7 Standards: Delay of compliance.

Pursuant to 40 CFR 60.692-7, delay of compliance of modified individual drain systems with ancillary downstream treatment components shall be allowed if compliance with the provisions of 40 CFR 60, subpart QQQ cannot be achieved without a refinery or process unit shutdown. Installation of equipment necessary to comply with the provisions of 40 CFR 60, Subpart QQQ shall occur no later than the next scheduled refinery or process unit shutdown.

Alternative standards for individual drain systems and oil-water separators are listed under 40 CFR 60.693-1 and 60.693-2, respectively.

(VIII) 40 CFR 60.695 Monitoring of operations.

(a) Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

(1) Where a thermal incinerator is used for VOC emission reduction, a temperature monitoring device equipped with a continuous recorder shall be used to measure the temperature of the gas stream in the combustion zone of the incinerator. The temperature monitoring device shall have an accuracy of +/- 1 percent of the temperature being measured, expressed in deg.C, or +/- 0.5 deg.C (0.9 deg.F), whichever is greater.

(2) Where a catalytic incinerator is used for VOC emission reduction, temperature monitoring devices, each equipped with a continuous recorder shall be used to measure the temperature in the gas stream immediately before and after the catalyst bed of the incinerator. The temperature monitoring devices shall have an accuracy of +/- 1 percent of the temperature being measured, expressed in deg.C, or +/- 0.5 deg.C (0.9 deg.F), whichever is greater.

(3) Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(i) For a carbon adsorption system that regenerates the carbon bed directly onsite, a monitoring device that continuously indicates and records the volatile organic compound concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

(4) Where a flare is used for VOC emission reduction, the owner or operator shall comply with the monitoring requirements of 40 CFR 60.18(f)(2).

(b) Where a VOC recovery device other than a carbon adsorber is used to meet the requirements specified in Sec. 60.692-5(a), the owner or operator shall provide to the Administrator information describing the operation of the control device and the process parameter(s) that would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

(c) An alternative operational or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

Performance test methods and procedures and compliance provisions are listed under 40 CFR 60.696; Record keeping requirements for this subpart are required under 40 CFR 60.697 and Reporting requirements are required under 40 CFR 60.698.

(g) The requirements of the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.50, Subpart E) are not included in the permit for the TGTU Incinerator because the incinerator does not combust any solid waste.

(h) The requirements of the National Emission Standards for Hazardous Air Pollutants, 40 CFR Part 63, Subpart EEE (National Emission Standards for Hazardous Air Polltuatants from Hazardous Waste Combustors) (326 IAC 20-28) are not included in the permit for the TGTU Incinerator because this incinerator does not combust any hazardous air pollutants.

(i) This facility is subject to 40 CFR 63, Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, because this source is a major source as defined in section 112(a) of the Clean Air Act and emits or has equipment containing or contacting benzene which is one or more of the hazardous air pollutants listed in table of 40 CFR 63, Subpart CC.

(1) For this modification, the storage tanks 22A and 710T-101 are subject to the requirements of 40 CFR 63.646 (Storage Vessel Provisions). The applicable requirements for these emission units are listed below.

(2) Fugitive emissions from the new emissions units being added including the Hydrotreater Unit, Amine Unit, Suflur Recovery Unit, and TGTU are subject to the requirements of 40 CFR 63.648 (Equipment Leak Standards) and must comply with the requirements of 40 CFR 60, Subpart VV. The applicable requirements for these emission units are listed below

40 CFR 63.642 General Standards - NESHAP for Petroleum Refineries
Pursuant to 40 CFR 63.642, the following shall apply to the source:

(a) Initial performance tests and initial compliance determinations shall be required only as specified in 40 CFR Part 63, Subpart CC.
(1) Performance tests and compliance determinations shall be conducted according to the schedule and procedures specified in this subpart.
(2) The Permittee shall notify the Administrator of the intention to conduct a performance test at least 30 days before the performance test is scheduled.

(3) Performance tests shall be conducted according to the provisions of 40 CFR 63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, a Permittee shall operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction.

(4) Data shall be reduced in accordance with the EPA-approved methods specified in the applicable section or, if other test methods are used, the data and methods shall be validated according to the protocol in Method 301 of appendix A of this part.

(b) The Permittee subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(c) All reports required under this subpart shall be sent to the Administrator at the addresses listed in 40 CFR 63.13 of subpart A of this part. If acceptable to both the Administrator and the Permittee of a source, reports may be submitted on electronic media.

(d) The Permittee of an existing source subject to the requirements of this subpart shall control emissions of organic HAPs to the level represented by the equation in 40 CFR 63.642(g).

(e) The Permittee of a new source subject to the requirements of this subpart shall control emissions of organic HAPs to the level represented by the equation in 40 CFR 63.642(g).

(f) The Permittee of an existing source shall demonstrate compliance with the emission standard in 40 CFR 63.642 paragraph (g) by following the procedures specified in 40 CFR 63.642 paragraph (k) for all emission points, or by following the emissions averaging compliance approach specified in 40 CFR 63.642 paragraph (l) for specified emission points and the procedures specified in 40 CFR 63.642 paragraph (k) for all other emission points within the source.

(g) The Permittee of a new source shall demonstrate compliance with the emission standard in 40 CFR 63.642 paragraph (h) only by following the procedures in 40 CFR 63.642 paragraph (k). The Permittee of a new source may not use the emissions averaging compliance approach.

(h) The Permittee of an existing source may comply, and the Permittee of a new source shall comply, with the miscellaneous process vent provisions in 40 CFR 63.643 through 63.645, the storage vessel provisions in 40 CFR 63.646, the wastewater provisions in 40 CFR 63.647, and the gasoline loading rack provisions in 40 CFR 63.650 of this subpart.

(1) The Permittee using this compliance approach shall also comply with the requirements of 40 CFR 63.654 as applicable.

(2) The Permittee using this compliance approach is not required to calculate the annual emission rate specified in 40 CFR 63.642 paragraph (g).

(i) The Permittee of an existing source may elect to control some of the emission points within the source to different levels than specified under 40 CFR 63.643 through 63.647, 40 CFR 63.650 and 63.651 by using an emissions averaging compliance approach as long as the overall emissions for the source do not exceed the emission level specified in 40 CFR 63.642 paragraph (d). The Permittee using emissions averaging shall meet the requirements in 40 CFR 63.642 paragraphs (i)(1) and (i)(2).

(1) Calculate emission debits and credits for those emission points involved in the emissions average according to the procedures specified in 40 CFR 63.652; and

(2) Comply with the requirements of 40 CFR 63.652, 63.653, and 63.654, as applicable.

(j) A State may restrict the Permittee of an existing source to using only the procedures in 40 CFR 63.642 paragraph (k) to comply with the emission standard in 40 CFR 63.642 paragraph (g) of this section. Such a restriction would preclude the source from using an emissions averaging compliance approach.

40 CFR 63.646 General Standards - NESHAP for Petroleum Refineries
Pursuant to 40 CFR 63.646, the following shall apply to the storage vessels:

(a) The Permittee of a Group 1 storage vessel subject to this subpart shall comply with the requirements of 40 CFR 63.119 through 63.121 except as provided in 40 CFR 63.646 paragraphs (b) through (l).

(b) As used in this section, all terms not defined in 40 CFR 63.641 shall have the meaning given them in 40 CFR part 63, Subparts A or G. The Group 1 storage vessel definition presented in 40 CFR 63.641 shall apply in lieu of the Group 1 storage vessel definitions presented in tables 5 and 6 of 40 CFR 63.119 of Subpart G of this part.

(1) A Permittee may use good engineering judgement or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(2) When a Permittee and IDEM, OAQ do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new source, Method 18 of 40 CFR part 60, appendix A shall be used.

(c) The following paragraphs do not apply to storage vessels at existing sources subject to this subpart: 40 CFR 63.119 (b)(5), (b)(6), (c)(2), and (d)(2).

(d) References shall apply as specified in 40 CFR 63.646 paragraphs (d)(1) through (d)(10).

(e) When complying with the inspection requirements of 40 CFR 63.120 of Subpart G of this part, owners and operators of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.

(f) Paragraphs (f)(1), (f)(2), and (f)(3) of 40 CFR 63.646 apply to Group 1 storage vessels at existing sources.

(g) Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

(h) References in 40 CFR 63.119 through 63.121 to 40 CFR 63.122(g)(1), 40 CFR 63.151, and references to initial notification requirements do not apply.

(i) References to the Implementation Plan in 40 CFR 63.120, paragraphs (d)(2) and (d)(3)(i) of 40 CFR 63.646 shall be replaced with the Notification of Compliance Status report.

(j) References to the Notification of Compliance Status report in 40 CFR 63.152(b) shall be replaced with 40 CFR 63.654(f).

(k) References to the Periodic Reports in 40 CFR 63.152(c) shall be replaced with 40 CFR 63.654(g).

(l) IDEM, OAQ can waive the notification requirements of 40 CFR 63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii) for all or some storage vessels at petroleum refineries subject to this subpart. IDEM, OAQ may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in 40 CFR 63.120(a)(6) or 63.120(b)(10)(iii) for all storage vessels at a refinery or for individual storage vessels on a case-by-case basis.

40 CFR 63.648 General Standards - Equipment Leak Standards
Pursuant to 40 CFR 63.648, the following standards shall apply to equipment leaks:

(a) The Permittee of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60 Subpart VV and 40 CFR 63.648 paragraph (b) except as provided in 40 CFR 63.648 paragraphs (a)(1), (a)(2), and (c) through (i). The Permittee of a new source subject to the provisions of this subpart shall comply with Subpart H of this part except as provided in 40 CFR 63.648 paragraphs (c) through (i).
  (1) For purposes of compliance with this section, the provisions of 40 CFR part 60, Subpart VV apply only to equipment in organic HAP service, as defined in 40 CFR 63.641 of this subpart.
  (2) Calculation of percentage leaking equipment components for Subpart VV of 40 CFR part 60 may be done on a process unit basis or a sourcewide basis. Once the Permittee has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(b) The use of monitoring data generated before August 18, 1995 to qualify for less frequent monitoring of valves and pumps as provided under 40 CFR part 60 Subpart VV or Subpart H of this part and paragraph (c) of this section (i.e., quarterly or semiannually) is governed by the requirements of 40 CFR 63.648 paragraphs (b)(1) and (b)(2).
  (1) Monitoring data must meet the test methods and procedures specified in 40 CFR 60.485(b) of 40 CFR part 60, Subpart VV or 40 CFR 63.180(b)(1) through (b)(5) of Subpart H of this part except for minor departures.
  (2) Departures from the criteria specified in 40 CFR 60.485(b) of 40 CFR part 60 Subpart VV or 40 CFR 63.180(b)(1) through (b)(5) of Subpart H of this part or from the monitoring frequency specified in Subpart VV or in 40 CFR 63.648 paragraph (c) (such as every 6 weeks instead of monthly or quarterly) are minor and do not significantly affect the quality of the data. An example of a minor departure is monitoring at a slightly different frequency (such as every 6 weeks instead of monthly or quarterly). Failure to use a calibrated instrument is not considered a minor departure.

(c) In lieu of complying with the existing source provisions of paragraph (a) of 40 CFR 63.648, a Permittee may elect to comply with the requirements of 40 CFR 63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of Subpart H of this part except as provided in 40 CFR 63.648 paragraphs (c)(1) through (c)(10) and (e) through (i).

(d) Upon startup of new sources, the Permittee shall comply with 40 CFR 63.163(a)(1)(ii) of Subpart H of this part for light liquid pumps and 40 CFR 63.168(a)(1)(ii) of Subpart H of this part for gas/vapor and light liquid valves.

(e) For reciprocating pumps in heavy liquid service and agitators in heavy liquid service, the Permittee is not required to comply with the requirements in 40 CFR 63.169 of Subpart H of this part.

(f) Reciprocating pumps in light liquid service are exempt from 40 CFR 63.163 and 60.482 if recasting the distance piece or reciprocating pump replacement is required.

(g) Compressors in hydrogen service are exempt from the requirements of paragraphs (a) and (c) of 40 CFR 63.648 if a Permittee demonstrates that a compressor is in hydrogen service.

(1) Each compressor is presumed not to be in hydrogen service unless a Permittee demonstrates that the piece of equipment is in hydrogen service.

(2) For a piece of equipment to be considered in hydrogen service, it must be determined that the percentage hydrogen content can be reasonably expected always to exceed 50 percent by volume.

(i) For purposes of determining the percentage hydrogen content in the process fluid that is contained in or contacts a compressor, the Permittee shall use either:

(A) Procedures that conform to those specified in 40 CFR 60.593(b)(2) of 40 part 60, Subpart GGG.

(B) Engineering judgment to demonstrate that the percentage content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume.

(aa) When a Permittee and the Administrator do not agree on whether a piece of equipment is in hydrogen service, the procedures in 40 CFR 63.648 paragraph (g)(2)(i)(A) of this section shall be used to resolve the disagreement.

(bb) If a Permittee determines that a piece of equipment is in hydrogen service, the determination can be revised only by following the procedures in 40 CFR 63.648 paragraph (g)(2)(i)(A) of this section.

(h) Each Permittee of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years.

(i) Reciprocating compressors are exempt from seal requirements if recasting the distance piece or compressor replacement is required.

General standards for this subpart are required under 40 CFR 63.642; storage vessels provisions are required under 40 CFR 63.646; Equipment leak standards are required under 40 CFR 63.648; gasoline loading rack provisions required under 40 CFR 63.650; emissions averaging provisions are required under 40 CFR 63.652; reporting and recordkeeping requirements are required under 40 CFR 63.654. These requirements are listed in detail in the Part 70 Permit.

(j) The three (3) boilers identified as B1, B2, and B3 are subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD. The boilers B1, B2, and B3 comprise one existing affected source for the large liquid fuel subcategory, as defined by 40 CFR 63.7506(b), because they meet the criteria in the definition in 40 CFR 63.7575 for the large liquid fuel subcategory. The provisions of 40 CFR 63 Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the affected sources after the effective date of 40 CFR 63, Subpart DDDDD, except when otherwise specified in 40 CFR 63 Subpart DDDDD. This rule was published in the *Federal Register* on September 13, 2004. A copy of the signed, final rule is available at http://www.epa.gov/ttn/atw/boiler/boilerpg.html.

Pursuant to 40 CFR 63.7506(b), the only requirements that apply to the existing affected sources for the large liquid fuel subcategory are the initial notification requirements in 40 CFR 63.9(b). The Permittee shall submit an Initial Notification containing the information specified in 40 CFR 63.9(b)(2) not later than 120 days after September 13, 2004, the effective date of 40 CFR 63, Subpart DDDDD as required by 40 CFR 63.7545(b).

(k) The Hydrotreater Unit Reactor Charge and Stabilizer Reboiler Heaters, identified as 122 and 123, respectively, to be constructed in 2005 are subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD. The Hydrotreater Unit Reactor Charge and Stabilizer Reboiler Heaters are new facilities and comprise one existing affected source for the large gaseous fuel subcategory, as defined by 40 CFR 63.7506(b), because they meet the criteria in the definition in 40 CFR 63.7575 for the large gaseous fuel subcategory. The provisions of 40 CFR 63 Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the affected sources after the effective date of 40 CFR 63, Subpart DDDDD, except when otherwise specified in 40 CFR 63 Subpart DDDDD. This rule was published in the *Federal Register* on September 13, 2004. A copy of the signed, final rule is available at http://www.epa.gov/ttn/atw/boiler/boilerpg.html.

The new facilities listed above are subject to National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD with the following conditions:

(I) 40 CFR 63.7490 Applicability and designation of affected facility:

(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in §63.7575.

(b) A boiler or process heater is new if the Permittee commences construction of the boiler or process heater after January 13, 2003, and meets the applicability criteria at the time the construction is commenced.

(c) A boiler or process heater is reconstructed if the Permittee meets the reconstruction criteria as defined in §63.2, the reconstruction is commenced after January 13, 2003, and the Permittee meets the applicability criteria at the time the reconstruction is commenced.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(II) 40 CFR 63.7500 Emission Limits and Work Practice Standards

(a) The Permittee shall meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) The Permitte must meet each emission limit and work practice standard in Table 1 of this subpart that applies to the boiler or process heater, except as provided under §63.7507.

(2) The Permittee must meet each operating limit in Tables 2 through 4 to this subpart that applies to the boiler or process heater. If the Permittee uses a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or wishes to establish and monitor an alternative operating limit and alternative monitoring parameters, the Permittee must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under §63.8(f).

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(III) 40 CFR 63.7505 – General Compliance Requirements

(a) The Permittee must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) The Permittee must always operate and maintain the affected source, including air pollution control and monitoring equipment, according to the revisions in §63.6(e)(1)(i).

(c) The Permittee can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit. Otherwise, The Permittee must demonstrate compliance using performance testing.

(d) If the Permittee demonstrate compliance with any applicable emission limit through performance testing, the Permittee must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies if the Permittee petitions the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each continuous monitoring system (CMS) required in this section, the Permittee must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. The Permittee must submit this site-specific monitoring plan at least 60 days before initial performance evaluation of the CMS.
   (i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);
   (ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and
   (iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(2) In the site-specific monitoring plan, the Permittee must also address paragraphs (d)(2)(i) through (iii) of this section.
   (i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (3), and (4)(ii);
   (ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and
   (iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(3) The Permittee shall conduct a performance evaluation of each CMS in accordance with the site-specific monitoring plan.

(4) The Permittee shall operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If the Permittee has an applicable emission limit or work practice standard, then the Permittee must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

Testing, Fuel Analyses, and Initial Compliance Requirements are required under 40 CFR 63.7510, 7515, and 7520; Performance Testing or Fuel Analysis provisions are required under 40 CFR Part 63.7515 through 63.7521; Emission averaging procedure is listed under 40 CFR 63.7522; Monitoring, Installation, operation, and maintenance requirements are listed under 40 CFR Part 63.7525;

(IV) 40 CFR Part 63.7545 - Notification, Reports, and Records

(a) The Permittee must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply by the dates specified.

(b) As specified in §63.9(b)(2), if the Permitte startup the affected source before the date of publication of the final rule in the federal register, the Permittee must submit an Initial Notification not later than 120 days after the date of publication of the final rule in the federal register. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of 40 CFR Part 63.7545, as applicable.

(c) As specified in §63.9(b)(3), if the Permittee startup a new or reconstructed affected source on or after the date of publication of the final rule in the federal register, the Permittee must submit an Initial Notification not later than 120 days after its become subject to this subpart. The Initial Notification must include the information required in paragraphs (c)(1) and (2) of 40 CFR Part 63.7545, as applicable.

(d) If the Permittee is required to conduct a performance test then the Permittee must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(e) If the Permittee is required to conduct an initial compliance demonstration as specified in §63.7530(a), then the Permittee must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, the Permittee must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(l) through (9) under 40 CFR Part 63.7545, as applicable.

(V) 40 CFR 63.7550 – Reporting Requirements

(a) The Permittee must submit each report in Table 9 to this subpart that applies to the Permittee.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), the Permittee must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of 40 CFR Part 63.7550.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of 40 CFR Part 63.7550.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where the Permittee is not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of 40 CFR Part 63.7550. This includes periods of startup, shutdown, and malfunction.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where the Permittee is using a CMS to comply with that emission limit, operating limit, or work practice standard, the Permittee must include the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (e)(1) through (12) of 40 CFR Part 63.7550. This includes periods of startup, shutdown, and malfunction and any deviations from the site-specific monitoring plan as required in §63.7505(d).

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If the Permittee operates a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and the Permittee intends to use a fuel other than natural gas or equivalent to fire the affected unit, then the Permittee must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of 40 CFR Part 63.7550.

(VI) 40 CFR Part 63.7555 – Record Keeping Requirements

(a) The Permittee must keep records according to paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that the Permittee submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that the Permittee submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, the Permittee must keep records according to paragraphs (b)(1) through (5) of 40 CFR Part 63.7555.

(c) The Permittee must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to the Permittee.

(d) For each boiler or process heater subject to an emission limit, the Permittee must also keep the records in paragraphs (d)(1) through (5) of 40 CFR Part 63.7555.

(e) If the boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, the Permittee must keep the records in paragraphs (e)(1) and (2) of 40 CFR Part 63.7555.

Pursuant to 40 CFR Part 63.7560:

(a) The records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), the Permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) The Permittee must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Permittee can keep the records off site for the remaining 3 years.

(l) This source is subject to the requirements of National Emission Standards for Hazardous Air Pollutants (NESHAP) for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units , and Sulfur Recovery Units, 326 IAC 20-14, 40 CFR 63, Subpart UUU, because this source is a major source of HAPs emissions and is a petroleum refinery engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code 2911 and mainly used for producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), and heating fuels (such as kerosene, fuel gas distillate, and fuel oils). This subpart applies to each new, reconstructed, or existing affected source at a petroleum refinery. As part of this modification, the affected emission units at the source include the new Sulfur Recovery Unit and TGTU, identified as 124, and the bypass lines serving these units.

This source with new emission units being constructed after April 11, 2002, must comply with the emission limitations and work practice standards for new or reconstructed affected sources in this subpart upon startup as specified in 40 CFR 63.1563 paragraph (a)(2).

(I) 40 CFR 63.1560 Applicability
Pursuant to 40 CFR 63.1560, the new Sulfur Recovery Unit and TGTU, and the associated bypass lines are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP), 326 IAC 20-14, (40 CFR 63, Subpart UUU), with a compliance date upon startup except as specified in 40 CFR 63.1563 paragraph (a)(2).

(II) 40 CFR 63.1568 Standards for HAP Emissions from Sulfur Recovery Unit.

(a) Pursuant to 40 CFR 63.1568, the following emission limitations and work practice standards shall apply to the Sulfur Recovery Unit and TGTU:

(1) The Permittee shall comply with each applicable emission limitation in Table 29 of this subpart. The Sulfur Recovery Unit and TGTU are not subject to the NSPS for SO_2, therefore, the Permittee must choose from the options in paragraphs (a)(1)(i) through (ii) of 40 CFR 63.1568:

(i) The Permittee can elect to meet the NSPS requirements (Option 1); or
(ii) The Permittee can elect to meet the total reduced sulfur (TRS) emission limitation (Option 2).

(2) The Permittee shall comply with each operating limit in Table 30 of this subpart.

(3) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate initial compliance with the emission limitations and work practice standards, the Permittee shall:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 31 of this subpart.
(2) Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in § 63.1571 and under the conditions specified in Table 32 of this subpart.
(3) Establish each site-specific operating limit in Table 30 of this subpart that applies according to the procedures in Table 32 of this subpart.
(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of this section.
(5) Demonstrate initial compliance with each emission limitation that applies according to Table 33 of this subpart.
(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of notification of compliance status.

(7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(c) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:

(1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies according to the methods specified in Tables 34 and 35 of this subpart.
(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in the operation, maintenance, and monitoring plan.

(III) 40 CFR 63.1569 - Standards for HAP Emissions from Bypass lines

(a) Pursuant to 40 CFR 63.1569, the following emission limitations and work practice standards shall apply to the bypass lines:

(1) The Permittee shall meet each work practice standard in Table 36 of this subpart. The Permittee can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:
   (i) The Permittee can elect to install an automated system (Option 1);
   (ii) The Permittee can elect to use a manual lock system (Option 2);
   (iii) The Permittee can elect to seal the line (Option 3); or
   (iv) The Permittee can elect to vent to a control device (Option 4).
(2) As provided in § 63.6(g), the EPA, may choose to grant permission to use an alternative to the work practice standard in paragraph (a)(1) of this section.
(3) The Permittee must prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate initial compliance with the emission limitations and work practice standards, the Permittee shall:

(1) If the Permittee elects the option in paragraph (a)(1)(i) of 40 CFR 63.1569, conduct each performance test for a bypass line according to the requirements in § 63.1571 and under the conditions specified in Table 37 of this subpart.
(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies according to Table 38 of this subpart.
(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this 40 CFR 63.1569 by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the notification of compliance status.
(4) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(c) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:
(1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies according to the requirements in Table 39 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of this section by complying with the procedures in the operation, maintenance, and monitoring plan.

(IV) 40 CFR 63.1570 General Compliance Requirements

(a) The Permittee shall comply with all of the non-opacity standards in this subpart during the times specified in 40 CFR 63.6(f)(1).

(b) The Permittee shall comply with the opacity and visible emission limits in this subpart during the times specified in 40 CFR 63.6(h)(1).

(c) The Permittee shall always operate and maintain the affected source, including air pollution control and monitoring equipment, according to the provisions in 40 CFR 63.6(e)(1)(i). During the period between the compliance date specified for the affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, the Permittee shall maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(d) The Permittee shall develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in 40 CFR 63.6(e)(3).

(e) During periods of startup, shutdown, and malfunction, the Permittee shall operate in accordance with the SSMP.

(f) The Permittee shall report each instance in which the Permittee did not meet each emission limitation and each applicable operating limit in this subpart. This includes periods of startup, shutdown, and malfunction. The Permitte also shall report each instance in which the Permittee did not meet the applicable work practice standards in this subpart. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in 40 CFR 63.1575.

(g) Consistent with 40 CFR 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates to IDEM, OAQ's satisfaction that the Permittee was operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). IDEM, OAQ will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 40 CFR 63.6(e) and the contents of the SSMP.

Performance testing and other initial compliance demonstration requirements are listed under 40 CFR 63.1571; Monitoring installation, operation, and maintenance requirements are required under 40 CFR 63.1572; Record keeping requirements for this subpart are required under 40 CFR 63.1576; Reporting requirements are required under 40 CFR 63.1575.

State Rule Applicability - Entire Source

326 IAC 2-2 (Prevention of Significant Deterioration)

This existing source permitted under Part 70 Permit No. 129-7882-00003 (issued on July 23, 2004), is a major stationary source because it is one of the 28 listed source categories (i.e. petroleum refineries) under 326 IAC 2-2, and potential sulfur dioxide (SO_2), volatile organic compound (VOC), carbon monoxide (CO), particulate matter (PM & PM-10) and nitrogen oxide (NOx) emissions after control are greater than 100 tons per year. This modification to an existing major stationary source is not major because the net emissions increase for each pollutant, after taking into consideration the contemporaneous decreases, is less than the applicable PSD significant threshold levels (see Potential to Emit for Modification after Issuance Table on page 8). To ensure that PM10 emissions do not exceed 15 tons per year, the usage of No. 6 fuel oil for boilers B1, B2, and B3 as a result of this modification shall be limited to 3,214.92 thousand gallons per twelve (12) consecutive month period with compliance determined at the end of each month. This fuel usage limitation will limit the total PM10 emissions from this modification to 14.49 tons per year. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

326 IAC 2-6 (Emission Reporting)

Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, this source is subject to 326 IAC 2-6 (Emission Reporting). The source also has potential to emit greater than or equal to 2,500 tons per year of sulfur dioxide; therefore, an emission statement covering the previous calendar year must be submitted by July 1 annually. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)

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

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

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

326 IAC 2-4.1-1 (New Source Toxics Control)

326 IAC 2-4.1-1 applies to new or reconstructed facilities with potential emissions of any single HAP equal or greater than ten (10) tons per twelve (12) month period and potential emissions of a combination of HAPs greater than or equal to twenty-five (25) tons per twelve (12) month period. This modification is not subject to 326 IAC 2-4.1-1 (New Source Toxics Control) because the potential to emit of single HAP and total HAPs is less than 10 and 25 tons per year, respectively.

State Rule Applicability - Individual Facilities

326 IAC 8-1-6 (New Facilities, General Reduction Requirements)

Rule 8-1-6 applies to new facilities (as of January 1, 1980) which have potential emissions of 25 tons or more per year of volatile organic compounds (VOC). The potential VOC emissions from this modification are below the twenty-five (25) tons per year applicability threshold and therefore, none of the new units are subject to the requirements of 326 IAC 8-1-6.

326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)

Storage tanks No. 22A and 710T-101, each with capacity greater than 39,000 gallons, store petroleum liquid whose true vapor pressure is less than 1.52 psi, therefore these storage tanks are not subject to the rule.

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)

The source is not subject to the requirements of 326 IAC 8-9 (Volatile Organic Liquid Storage Vessels) because this source is not located in one of the listed counties and was constructed prior to January 1, 1980.

326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating)

The three (3) refinery fuel gas fired boilers B1, B2, and B3 burning No. 6 fuel oil as a back-up, rated at 52, 65, and 52 MMBtu/hr, are subject to the particulate matter limitations of 326 IAC 6-2-3 because each boiler was constructed prior to September 21, 1983. These boilers are being allowed to burn additional No. 6 fuel oil through this modification. Pursuant to T129-7882-00003, issued on July 23, 2003, these boilers B1, B2, and B3 are limited to 0.40, 0.25 and 0.40 lb PM/MMBtu, respectively, based on the following equation:

$$Pt = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where:
C = maximum ground level concentration (50 µg/m3, for a period not to exceed 60 min.)
Pt = maximum allowable particulate matter (PM) emitted per MMBtu heat input
Q = total source max. indirect heater input
N = Number of stacks in fuel burning operation.
a = plume rise factor (0.67, for Q < 1,000)
h = Stack height in feet

Actual lbs PM/MMBtu (0.08, 0.08, 0.08) are less than allowable lbs PM/MMBtu (0.40, 0.25, 0.40), therefore the boilers (ID Nos. B1, B2 and B3) will continue to comply with the requirements of 326 IAC 6-2.

326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations)

Three (3) boilers B1, B2, and B3 are subject to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations) because each boiler has potential SO_2 emissions greater than 25 tons per year. The sulfur dioxide emissions from the boilers B1, B2, and B3, when No. 6 residual fuel oil is used, shall be limited to 1.6 pounds per million British thermal units heat input. This equates to a distillate fuel oil sulfur content limit of 1.70%. Therefore, the sulfur content of the distillate fuel must be less than or equal to 1.70% in order to comply with this rule. Based on the information submitted, the sulfur content of the No. 6 residual fuel oil is 0.8%. Therefore, the burner combustion of No. 6 residual fuel oil complies with the rule. This rule is not applicable to other combustion units in this modification since only refinery fuel gas or natural gas will be combusted.

326 IAC 7-2-1 (Sulfur Dioxide Reporting Requirements)

Pursuant to this rule, the source shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate (pounds SO_2 per MMBtu), to IDEM, OAQ upon request.

326 IAC 4-2 (Incinerators)

The sour flare used to control emissions from the Sulfur Recovery Unit, Incinerator burner (124-2) and TGTU incinerator (124-3) are not subject to the requirements of rule 326 IAC 4-2 since the flare does not meet the definition of an incinerator provided in 326 IAC 1-2-34.

Compliance Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with applicable state and federal rules on a more or less continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a more or less continuous demonstration. When this occurs IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, compliance requirements are divided into two sections: Compliance Determination Requirements and Compliance Monitoring Requirements.

Compliance Determination Requirements in Section D of the permit are those conditions that are found more or less directly within state and federal rules and the violation of which serves as grounds for enforcement action. If these conditions are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The compliance monitoring requirements applicable to this source are as follows:

(a) The Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2), and Sour Flare (124-4) have applicable compliance monitoring conditions as specified below:

Pursuant to 40 CFR 60.105, Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fuel gas combustion devices subject to 40 CFR 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of 40 CFR 60.105. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO_2 and 25 percent oxygen (O2).

(ii) The SO_2 monitoring level equivalent to the H_2S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(2) In place of the SO_2 monitor in paragraph (a)(3) of 40 CFR 60.105, an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H_2S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

(iii) The performance evaluations for this H_2S monitor under Sec. 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(3) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to 40 CFR 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.
   (i) The span values for this monitor are 500 ppm O_2 and 25 percent O_2.
   (ii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(4) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105 are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(5) The Permittee shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105.
   (i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the 40 CFR 60.13(e) performance evaluation.
   (ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

The monitoring conditions are necessary because the Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2), and Sour Flare (124-4) must operate properly to ensure compliance with NSPS [40 CFR 60, Subpart J] and 326 IAC 2-7 (Part 70).

(b) The Sulfur Recovery Unit and TGTU, identified as 124, and the bypass lines serving these units have applicable compliance monitoring conditions as specified below:

(1) The Permittee shall comply with all of the non-opacity standards in 40 CFR Part 63 during the times specified in 40 CFR 63.6(f)(1).

(2) The Permittee shall comply with the opacity and visible emission limits in this subpart during the times specified in 40 CFR 63.6(h)(1).

(3) The Permittee shall always operate and maintain the affected source, including air pollution control and monitoring equipment, according to the provisions in 40 CFR 63.6(e)(1)(i). During the period between the compliance date specified for the affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, the Permittee shall maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(4) The Permittee shall develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in 40 CFR 63.6(e)(3).

(5) During periods of startup, shutdown, and malfunction, the Permittee shall operate in accordance with the SSMP.

(6) The Permittee shall report each instance in which the Permittee did not meet each emission limitation and each applicable operating limit in this subpart. This includes periods of startup, shutdown, and malfunction. The Permitte also shall report each instance in which the Permittee did not meet the applicable work practice standards in this subpart. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in 40 CFR 63.1575.

(7) Consistent with 40 CFR 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates to IDEM, OAQ's satisfaction that the Permittee was operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). IDEM, OAQ will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 40 CFR 63.6(e) and the contents of the SSMP.

(8) The Permittee shall install, operate, and maintain each continuous emission monitoring system as follows (listed under 40 CFR 63.1572 (h)(1) through (4)):
- (i) The Permittee shall install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of this subpart.
- (ii) If the Permittee uses a continuous emission monitoring system to meet the NSPS CO or SO_2 limit, then the Permittee shall conduct a performance evaluation of each continuous emission monitoring system according to the requirements in 40 CFR 63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.
- (iii) As specified in 40 CFR 63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
- (iv) Data must be reduced as specified in 40 CFR 63.8(g)(2).

(9) The Permittee shall install, operate, and maintain each continuous opacity monitoring system as follows (listed under 40 CFR 63.1572 (i)(1) through (3)).
- (i) Each continuous opacity monitoring system must be installed, operated, and maintained according to the requirements in Table 40 of this subpart.
- (ii) If the Permittee uses a continuous opacity monitoring system to meet the NSPS opacity limit, then the Permittee shall conduct a performance evaluation of each continuous opacity monitoring system according to the requirements in 40 CFR 63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.
- (iii) As specified in 40 CFR 63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(10) The Permittee shall install, operate, and maintain each continuous parameter monitoring system as follows (listed under 40 CFR 63.1572 (j)(1) through (7)):

(i) Each continuous parameter monitoring system must be installed, operated, and maintained according to the requirements in Table 41 of this subpart and in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately.

(ii) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. The Permittee shall have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).

(iii) Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.

(iv) Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day. The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.

(v) Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.

(11) The Permittee shall monitor and collect data as follows (listed under 40 CFR 63.1572 (k)(1) and (2)):

(i) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(ii) The Permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. The Permittee shall use all the data collected during all other periods in assessing the operation of the control device and associated control system.

The monitoring conditions are necessary because the Sulfur Recovery Unit and TGTU, identified as 124, and the bypass lines serving these units must operate properly to ensure compliance with NESHAP [40 CFR 63, Subpart UUU] and 326 IAC 2-7 (Part 70).

(c) The storage tanks 22A and 710T-101, Hydrotreater Unit, Amine Unit, Suflur Recovery Unit, and TGTU have applicable compliance monitoring conditions as specified below:

(a) For each emission point included in an emissions average, the Permittee shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with 40 CFR 63.643 through 63.647, and 40 CFR 63.650 and 63.651. The specific requirements for the affected facilities are identified in 40 CFR 63.653 paragraphs (a)(3) and (a)(7).

(1) The source shall implement the following procedures for each storage vessel controlled with an internal floating roof, external roof, or a closed vent system with a control device, as appropriate to the control technique:

(i) Perform the monitoring or inspection procedures in 40 CFR 63.646 of this subpart and 40 CFR 63.120 of Subpart G; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in 40 CFR 63.646 of this subpart and 40 CFR 63.120(d) of Subpart G.

(2) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in 40 CFR 63.643 through 63.647 and 40 CFR 63.650 and 63.651, the Permittee shall establish a site-specific monitoring parameter and shall submit the information specified in 40 CFR 63.654(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by 40 CFR 63.654 shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by 40 CFR 63.654.

(d) Each Permittee of an existing source who elects to comply with 40 CFR 63.654 (g) and (h) by using emissions averaging for any emission points shall submit an Implementation Plan.

(1) The Implementation Plan shall be submitted to the Administrator and approved prior to implementing emissions averaging. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, in a Notification of Compliance Status Report, in a Periodic Report or in any combination of these documents. If a Permittee submits the information specified in 40 CFR 63.653 paragraph (d)(2) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating the previously submitted information.

(2) The Implementation Plan shall include the information specified in 40 CFR 63.653 paragraphs (d)(2)(i) through (d)(2)(viii) for all points included in the average.

(3) The Administrator shall determine within 120 calendar days whether the Implementation Plan submitted presents sufficient information. The Administrator shall either approve the Implementation Plan, request changes, or request that the Permittee submit additional information. Once the Administrator receives sufficient information, the Administrator shall approve, disapprove, or request changes to the plan within 120 calendar days.

These monitoring conditions are necessary because the source must comply with [40 CFR 63, Subpart CC], and 326 IAC 2-7 (Part 70).

(e) The boilers B1, B2, and B3 will continue to be subject to the compliance monitoring requirements listed under Condition D.5.7 of the Part 70 Permit No. 129-7882-00003.

Changes Proposed

The changes listed below have been made to the Part 70 Operating Permit (T129-7882-00003).

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

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

(b) one (1) Fluid Catalytic Cracking Unit (FCCU) **Raw Oil** ~~p~~**P**re**-**heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas **only (no H_2S combustion)**, installed in 1945 and exhausting to stack 9;

****

(d) The following storage vessels:

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
169	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1989	113;
125	**fixed roof cone tank**	**157,000**	**6,000**	**hydrocarbon with vapor pressure of No.2 fuel oil or less**	**2005**	**015;**

****

(f) one (1) Crude heater **equipped with Low-NOx burner**, identified as C-II with a maximum heat input rate of 131 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1955 and exhausting to stack 1;

****

(t) two (2) sets of Oil/water Separators **equipped with covers for VOC control**, identified as 071;

****

(ii) process units made up of vessels, piping, exchangers, identified as PENEX.

(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (to be constructed in 2005).

(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 (to be constructed in 2005).

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:

(1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).

(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of:

(1) pipeline Valves - Gas, identified as 090;
(2) pipeline Valves - Light Liquid, identified as 091;
(3) pipeline Valves - Heavy Liquid, identified as 092;
(4) pipeline Valves - Hydrogen, identified as 093;
(5) open Ended Valves, identified as 094;
(6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(7) flanges, identified as 095;
(8) pump Seals Light Liquid, identified as 096;
(9) pump Seals Heavy Liquid, identified as 097;
(10) compressor Seals - Gas, identified as 098;
(11) compressor Seals - Heavy Liquid, identified as 099;
(12) drains, identified as 100;
(13) vessel Relief Valves, identified as 101; and
(14) cooling Towers, identified as 119.

SECTION D.2 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(a) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74.

(b) One (1) FCCU regenerator, identified as V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10.

(c) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (to be constructed in 2005).

(d) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 (to be constructed in 2005).

(e) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:

(1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).

(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).

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

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

D.2.1 General Provisions Relating to HAPs [326 IAC 12-1-1] [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to one (1) CCR platformer described in this section except when otherwise specified in 40 CFR Part 60, Subpart J.

D.2.2 General Provisions Relating to HAPs [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

(a) The provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facilities described in this section except when otherwise specified in 40 CFR Part 63, Subpart UUU.

(b) The provisions of 40 CFR 63 Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the affected sources, as designated by 40 CFR 63.7506(b). The Permittee must comply with these requirements on and after the effective date of 40 CFR 63, Subpart DDDDD.

D.2.3 Petroleum Refineries NSPS [326 IAC 12-1-1] [40 CFR 60, Subpart J]

The CCR Platformer Heater**, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2), and Sour Flare (124-4) are** ~~is~~ subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.100, Subpart J) "Standards of Performance for Petroleum Refineries," because the refinery fuel gas combustion device**s** commenced construction or modification after June 11, 1973.

D.2.4 Petroleum Refineries NESHAP [326 IAC 20-1-1] [40 CFR 63, Subpart UUU]

Pursuant to 40 CFR 63.1560, the ~~existing~~ one (1) **existing** catalytic cracking unit and one (1) catalytic reforming unit, known as FCCU regenerator and CCR Platformer Unit, respectively, **and the new Sulfur Recovery Unit and TGTU, identified as 124, and the bypass lines serving these units** are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP), 326 IAC 20-14, (40 CFR 63, Subpart UUU), with a compliance date of April 11, 2005 except as specified in 40 CFR 63.1563 paragraph (c).

The Permittee shall submit a notification of compliance options chosen no later than 180 days prior to the initial compliance date, which is April 11, 2005. The notification of compliance options chosen shall contain all the information required in 40 CFR 63.1570 through 63.1573 that is appropriate for the facility.

D.2.5 Standards for Sulfur Oxides Emissions from Fuel Gas Combustion Devices [40 CFR 60.104] **[326 IAC 12]**

Pursuant to 40 CFR 60.104, the following shall apply to the CCR Platformer Heater**, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2)**:

The Permittee that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

No Permittee subject to the provisions of this subpart shall burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

D.2.6 NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]

Pursuant to 40 CFR 63.7490, the provisions of 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, apply to the Hydrotreater Unit Reactor Charge and Stabilizer Reboiler Heaters, identified as 122 and 123, respectively, because these are new facilities being constructed after January 13, 2003 and meet the criteria in the definition in 40 CFR 63.7575 for the large gaseous fuel subcategory.

D.2.~~6~~**7** Standards for Metal HAP Emissions from Catalytic Cracking Units [40 CFR 63.1564]

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D.2.~~7~~**8** Standards for Organic HAP Emissions from Catalytic Cracking Units [40 CFR 63.1565]

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D.2.~~8~~**9** Standards for Organic HAP Emissions from Catalytic Reforming Units [40 CFR 63.1566]

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D.2.~~9~~**10** Standards for Inorganic HAP Emissions from Catalytic Reforming Units [40 CFR 63.1567]

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D.2.11 Standards for HAP Emissions from Sulfur Recovery Units [40 CFR 63.1568] [326 IAC 20-50-1]

(a) Pursuant to 40 CFR 63.1568, the following emission limitations and work practice standards shall apply to the Sulfur Recovery Unit and TGTU:

(1) The Permittee shall comply with each applicable emission limitation in Table 29 of this subpart. The Sulfur Recovery Unit and TGTU are not subject to the NSPS for SO_2, therefore, the Permittee must choose from the options in paragraphs (a)(1)(i) through (ii) of 40 CFR 63.1568:

(i) The Permittee can elect to meet the NSPS requirements (Option 1); or

(ii) The Permittee can elect to meet the total reduced sulfur (TRS) emission limitation (Option 2).

(2) The Permittee shall comply with each operating limit in Table 30 of this subpart.

(3) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:

(1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies according to the methods specified in Tables 34 and 35 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this 40 CFR 633.1568 by complying with the procedures in the operation, maintenance, and monitoring plan.

D.2.12 Standards for HAP Emissions from Bypass Lines [40 CFR 63.1569] [326 IAC 20-50-1]

(a) Pursuant to 40 CFR 63.1569, the following emission limitations and work practice standards shall apply to the bypass lines:

(1) The Permittee shall meet each work practice standard in Table 36 of this subpart. The Permittee can choose from the four options in paragraphs (a)(1)(i) through (iv) of 40 CFR 63.1569:

(i) The Permittee can elect to install an automated system (Option 1);

(ii) The Permittee can elect to use a manual lock system (Option 2);

(iii) The Permittee can elect to seal the line (Option 3); or

(iv) The Permittee can elect to vent to a control device (Option 4).

(2) As provided in § 63.6(g), the EPA, may choose to grant permission to use an alternative to the work practice standard in paragraph (a)(1) of 40 CFR 63.1569.

(3) The Permittee must prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:

(1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies according to the requirements in Table 39 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of 40 CFR 63.1569 by complying with the procedures in the operation, maintenance, and monitoring plan.

D.2.13 Emission Limits and Work Practice Standards [40 CFR Part 63, Subpart DDDDD]

Pursuant to 40 CFR 63.7500, the Permittee shall comply with the following requirements.

(a) The Permitte shall meet each emission limit and work practice standard in Table 1 of this subpart that applies to the boiler or process heater, except as provided under §63.7507.

(b) The Permittee must meet each operating limit in Tables 2 through 4 to this subpart that applies to the boiler or process heater. If the Permittee uses a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or wishes to establish and monitor an alternative operating limit and alternative monitoring parameters, the Permittee must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under §63.8(f).

As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

D.2.1~~0~~**4** Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the CCR platformer heater, identified as 300 - H1, H2, H3, FCCU regenerator, identified as V-5, **Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator burner (124-2) and TGTU incinerator (124-3)** and any control devices.

Compliance Determination Requirements [326 IAC 2-1.1-11] [326 IAC 2-7-6(1)]

D.2.1~~1~~**5** Performance Testing [40 CFR 60.106] [326 IAC 12]

During the period between 30 and 36 months after issuance of this permit, in order to demonstrate compliance with Condition D.2.5, the Permittee shall perform H_2S testing for the CCR Platformer Heater**, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2)** utilizing methods as approved by the Commissioner. ~~This test shall be repeated at least once every five (5) years from the date of this valid compliance demonstration.~~ Testing shall be conducted in accordance with Section C-Performance Testing.

Pursuant to 40 CFR 60.106, the following test methods and procedures shall apply to the refinery fuel gas combustion device:

(a) In conducting the performance tests required in 60.8, the Permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in 60.8(b).

(b) The Permittee shall determine compliance with the H_2S standard in 60.104(a)(1) as follows: Method 11 shall be used to determine the H_2 concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

D.2.1~~2~~**6** Initial Compliance Demonstration [40 CFR 63.1564 **– 1569** ~~, 1565, 1566, and 1567~~] **[326 IAC 20-50-1]**

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(e) To demonstrate initial compliance with the emission limitations and work practice standards for Sulfur Recovery Units, the Permittee shall:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 31 of this subpart.

(2) Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in § 63.1571 and under the conditions specified in Table 32 of this subpart.

(3) Establish each site-specific operating limit in Table 30 of this subpart that applies according to the procedures in Table 32 of this subpart.

(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of 40 CFR 63.1568.

(5) Demonstrate initial compliance with each emission limitation that applies according to Table 33 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of 40 CFR 63.1568 by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of notification of compliance status.

(7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(f) To demonstrate initial compliance with the emission limitations and work practice standards for Bypass Lines, the Permittee shall:

(1) If the Permittee elects the option in paragraph (a)(1)(i) of 40 CFR 63.1569, conduct each performance test for a bypass line according to the requirements in § 63.1571 and under the conditions specified in Table 37 of this subpart.

(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies according to Table 38 of this subpart.

(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this 40 CFR 63.1569 by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the notification of compliance status.

(4) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

D.2.1~~3~~**7** Performance Testing [40 CFR 63.1571] [326 IAC 20]

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D.2.18 Testing, Fuel Analyses, and Initial Compliance Requirements [40 CFR 63.7510] [40 CFR 63.7515] [40 CFR 63.7520]

Pursuant to 40 CFR 63.7510, the Permittee shall comply with the following initial compliance requirements:

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, the initial compliance requirements include conducting performance tests according to §63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in the boiler or process heater according to §63.7521 and Table 6 of this subpart, establishing operating limits according to §63.7530 and Table 7 of this subpart, and conducting CMS performance evaluations according to §63.7525.

(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, the initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in the boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart.

(c) For affected sources that have an applicable work practice standard, the initial compliance requirements depend on the subcategory and rated capacity of the boiler or process heater. If the boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, then the initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If the boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, then the initial compliance demonstration is conducting a performance evaluation of the continuous emission monitoring system for carbon monoxide according to §63.7525(a).

(d) For existing affected sources, the Permittee must demonstrate initial compliance no later than 180 days after the compliance date that is specified for the source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart.

(e) If the new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and September 13, 2004, then the Permittee must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after September 13, 2004 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(f) If the new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and September 13, 2004, and the Permittee choses to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, the Permittee must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after September 13, 2004 or within 3 years after startup of the affected source, whichever is later.

(g) If the new or reconstructed affected source commences construction or reconstruction after September 13, 2004, then the Permittee must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

Pursuant to 40 CFR 63.7510, the Permittee shall comply with the following performance test requirements:

(a) The Permittee must conduct all applicable performance tests according to §63.7520 on an annual basis, unless the permittee follows the requirements listed in paragraphs (b) through (d) of 40 CFR 63.7510. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless the Permittee follows the requirements listed in paragraphs (b) through (d) of 40 CFR 63.7510.

(b) The permittee can conduct performance tests less often for a given pollutant if the performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that the Permittee complies with the emission limit. In this case, the Permittee does not have to conduct a performance test for that pollutant for the next 2 years. The Permittee must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If the boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, the Permittee may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, the Permittee must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If the Permittee has an applicable work practice standard for carbon monoxide and the boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, the Permittee must conduct annual performance tests for carbon monoxide according to §63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

(f) The Permittee must conduct a fuel analysis according to §63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If the Permittee burns a new type of fuel, then the Permittee must conduct a fuel analysis before burning the new type of fuel in the boiler or process heater. The Permittee must still meet all applicable continuous compliance requirements in §63.7540.

(g) The Permittee must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for the affected source have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550.

Pursuant to 40 CFR 63.7520, the Permittee is subject to the following performance test procedures:

(a) The Permittee must conduct all performance tests according to §63.7(c), (d), (f), and (h). The Permittee must also develop a site-specific test plan according to the requirements in §63.7(c) if the Permittee elects to demonstrate compliance through performance testing.

(b) The Permittee must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(d) The Permittee must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. The Permittee must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and the Permittee must demonstrate initial compliance and establish the operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.

(e) The Permittee may not conduct performance tests during periods of startup, shutdown, or malfunction.

(f) The Permittee must conduct three separate test runs for each performance test required in 40 CFR 63.7520, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(g) To determine compliance with the emission limits, the Permittee must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

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

D.2.~~14~~**19** Continuous Monitoring [40 CFR 60.105] [326 IAC 12]

(a) Pursuant to 40 CFR 60.105, the CCR Platformer Heater, identified as 300 - H1, H2, H3, has applicable compliance monitoring conditions as specified below:

Pursuant to a September 16, 1984 letter from the USEPA, an Alternative monitoring plan was approved with the following conditions.

(~~a~~**1**) The fuel gas must be sampled every 8 hours during the unit's operation at the representative location and analyze the H_2S concentration using three Draeger tubes with a span of 0-15 parts per million (ppm) for each sampling effort.

(~~b~~**2**) Average the Draeger tube readings for each sampling event.

(~~c~~**3**) If the results H_2S concentrations exceed 10 ppm, within 1 hour begin performing H_2S sampling and analysis every hour using three Draeger tubes with a span of 0-200 ppm.

(~~d~~**4**) When 3 consecutive hours of sampling with the 200 ppm Draeger tubes indicate that the H_2S concentration is below 10 ppm, revert to using the 15 ppm Draeger tubes every 8 hours.

(~~e~~**5**) If the H_2S ever exceeds 80 ppm, install and certify an H_2S CEM within 180 days and, in the meantime, follow this approved alternative monitoring method.

(~~f~~**6**) Submit quarterly summary reports indicating all instances when the H_2S concentration exceeded 10 ppm, the actual H_2S concentration, and times when the unit was not operational.

(~~g~~**7**) Maintain records of the Draeger tube results used to prepare the quarterly reports on file for at least 2 years.

(b) Pursuant to 40 CFR 60.105, the Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2) have applicable compliance monitoring conditions as specified below:

(1) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(a) For fuel gas combustion devices subject to 40 CFR 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of 40 CFR 60.105. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO2 and 25 percent oxygen (O2).

(ii) The SO_2 monitoring level equivalent to the H_2S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(b) In place of the SO_2 monitor in paragraph (a)(3) of 40 CFR 60.105, an instrument for continuously monitoring and recording the concentration (dry basis) of H2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H2S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned.

(iii) The performance evaluations for this H2S monitor under Sec. 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(c) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to 40 CFR 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm O2 and 25 percent O2.

(ii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(d) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105 are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(e) The Permittee shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of 40 CFR 60.105.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the 40 CFR 60.13(e) performance evaluation.

(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

D.2.~~15~~**20** General Compliance Requirements [40 CFR 63.1570] **[326IAC 20-50-1]**

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D.2.~~16~~**21** Monitoring Installation, Operation, and Maintenance Requirements [40 CFR 63.1572] **[326 IAC 20-50-1]**

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D.2.22 General Compliance Requirements [40 CFR 63.7505]

Pursuant to 40 CFR 63.7505, the Permittee shall comply with the following requirements:

(a) The Permittee shall be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) The Permittee shall always operate and maintain the affected source, including air pollution control and monitoring equipment, according to the revisions in §63.6(e)(1)(i).

(c) The Permittee can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit. Otherwise, The Permittee must demonstrate compliance using performance testing.

(d) If the Permittee demonstrate compliance with any applicable emission limit through performance testing, the Permittee must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of 40 CFR 63.7505. This requirement also applies if the Permittee petitions the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each continuous monitoring system (CMS) required in 40 CFR 63.7505, the Permittee must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of 40 CFR 63.7505. The Permittee must submit this site-specific monitoring plan at least 60 days before initial performance evaluation of the CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(2) In the site-specific monitoring plan, the Permittee must also address paragraphs (d)(2)(i) through (iii) of this 40 CFR 63.7505.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (3), and (4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(3) The Permittee shall conduct a performance evaluation of each CMS in accordance with the site-specific monitoring plan.

(4) The Permittee shall operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If the Permittee has an applicable emission limit or work practice standard, the Permittee must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

D.2.23 Monitoring, Installation, Operation, and Maintenance Requirements [40 CFR 63.7505]

Pursuant to 40 CFR 63.7505, the Permittee shall comply with the following requirements:

(a) If the Permittee has an applicable work practice standard for carbon monoxide, and the boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, then the Permittee must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of this 40 CFR 63.7505 by the compliance date specified in §63.7495.

(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to §63.7505(d).

(2) The Permittee must conduct a performance evaluation of each CEMS according to the requirements in §63.8 and according to PS 4A of 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in §63.8(g)(2).

(5) The Permittee must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, the Permittee must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when the boiler or process heater is operating at less than 50 percent of its rated capacity. The Permittee must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitute a deviation from the monitoring requirements.

(b) If the Permittee has an applicable opacity operating limit, then the Permittee must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of 40 CFR 63.7505 by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.

(2) The Permittee must conduct a performance evaluation of each COMS according to the requirements in §63.8 and according to PS 1 of 40 CFR part 60, appendix B.

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) The Permittee must include in the site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) The Permittee must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) The Permittee must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.

(c) If the Permittee has an operating limit that requires the use of a CMS, then the Permittee must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of 40 CFR 63.7505 by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. The Permittee must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent , not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, the Permittee must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. The Permittee must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of 40 CFR 63.7505.

(5) Record the results of each inspection, calibration, and validation check.

(d) If the Permittee has an operating limit that requires the use of a flow measurement device, then the Permittee must meet the requirements in paragraphs (c) and (d)(1) through (4) of 40 CFR 63.7505.

(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.

(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) Conduct a flow sensor calibration check at least semiannually.

(e) If the Permittee has an operating limit that requires the use of a pressure measurement device, then the Permittee must meet the requirements in paragraphs (c) and (e)(1) through (6) of 40 CFR 63.7505.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(f) If the Permittee has an operating limit that requires the use of a pH measurement device, then the Permittee must meet the requirements in paragraphs (c) and (f)(1) through (3) of this 40 CFR 63.7505.

(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(g) If the Permittee has an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), then the Permittee must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(h) If the Permittee has an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), then the Permittee must meet the requirements in paragraphs (c) and (h)(1) through (3) of 40 CFR 63.7505.

(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.
(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.
(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.

(i) If the Permittee elects to use a fabric filter bag leak detection system to comply with the requirements of this subpart, then the Permittee must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of 40 CFR 63.7505.
(1) The Permittee must install and operate a bag leak detection system for each exhaust stack of the fabric filter.
(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA-454/R-98-015, September 1997.
(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.
(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.
(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.
(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.
(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.
(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

D.2.24 Initial Compliance with the Emission Limits and Work Practice Standards [40 CFR 63.7530]

Pursuant to 40 CFR 63.7530, the Permittee shall comply with the following requirements:

(a) The Permitte must demonstrate initial compliance with each emission limit and work practice standard that applies to Permittee by either conducting initial performance tests and establishing operating limits, as applicable, according to §63.7520, paragraph (c) of 40 CFR 63.7530, and Tables 5, 7 and 8 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to §63.7521, paragraph (d) of 40 CFR 63.7530, and Tables 6 and 8 to this subpart.

(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(c) If the Permittee demonstrates compliance through performance testing, then the Permittee must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to the Permittee according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (c)(4) of 40 CFR 63.7530, as applicable. The Permittee must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of 40 CFR 63.7530, as applicable.

(d) If the Permittee elects to demonstrate compliance with an applicable emission limit through fuel analysis, then the Permittee must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (d)(1) through (5) of 40 CFR 63.7505.

(e) The Permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

D.2.25 Continuous Compliance Requirements [40 CFR 63.7530]

Pursuant to 40 CFR 63.7530, the Permittee shall comply with the following requirements:

(a) The Permittee must monitor and collect data according to 40 CFR 63.7530 and the site-specific monitoring plan required by §63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) The Permittee may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The Permittee must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.

Pursuant to 40 CFR 63.7540, the Permittee shall use the following to demonstrate continuous compliance with the emission limits and work practice standards.

(a) The Permittee must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to the Permittee according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of 40 CFR 63.7540.

(b) The Permittee must report each instance in which the Permittee did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply. The Permittee must also report each instance during a startup, shutdown, or malfunction when the Permittee did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, the Permittee must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §§63.6(e)and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates to the EPA Administrator's satisfaction that the Permittee was operating in accordance with the SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

(e) Following the compliance date, the Permittee must demonstrate continuous compliance under the emission averaging provision with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of 40 CFR 63.7541.

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

D.2.1~~7~~**26**Record Keeping Requirements

(a) To document compliance with Conditions D.2.5 and D.2.~~14~~**19**, the Permittee shall maintain records of the concentration of H_2S in fuel gases by ~~Draeger tube testing~~ **methods** defined under Condition D.2.~~14~~**19**.

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

D.2.~~18~~**27** Record Keeping Requirements [40 CFR 63.1576]

(a) The Permittee shall keep the records specified in 40 CFR 63.1576 paragraphs (a)(1) through (3).
   (1) A copy of each notification and report that the Permittee submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status that the Permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).
   (2) The records in 40 CFR 63.6(e)(1)(iii) through (v) related to startup, shutdown, and malfunction.
   (3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in 40 CFR 63.10(b)(2)(viii).

(b) To document compliance with Conditions D.2.~~15~~**20**, the Permittee shall maintain records of all the applicable parameters listed in Condition D.2.~~15~~**20**.

(c) To document compliance with Condition D.2.~~16~~**21**, the Permittee shall keep the records required in 40 CFR 63.1576 paragraphs (b)(1) through (5).
   (1) Records described in 40 CFR 63.10(b)(2)(vi) through (xi).
   (2) Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in 40 CFR 63.6(h)(7)(i) and (ii).
   (3) Previous (i.e., superceded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).
   (4) Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in 40 CFR 63.8(f)(6)(i).
   (5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(d) The Permittee shall keep the records in 40 CFR 63.6(h) for visible emission observations.

(e) The Permittee shall keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); and Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); **Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines)** to show continuous compliance with each applicable emission limitation.

D.2.~~19~~**28** Notifications [40 CFR Part 63.1574] **[326 IAC 20-50-1]**

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D.2.~~20~~**29**Reporting Requirements [40 CFR Part 63.1575] **[326 IAC 20-50-1]**

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D.2.30 Notification Requirements [40 CFR Part 63.7545]

Pursuant to 40 CFR 63.7545, the Permittee shall comply with the following notification requirements:

(a) The Permittee must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply by the dates specified.

(b) As specified in §63.9(b)(2), if the Permitte startup the affected source before the date of publication of the final rule in the federal register, the Permittee must submit an Initial Notification not later than 120 days after the date of publication of the final rule in the federal register. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of 40 CFR 63.7545, as applicable.

(1) If the affected source has an annual capacity factor of greater than 10 percent, then the Initial Notification must include the information required by §63.9(b)(2).

(2) If the affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), then the Initial Notification must include the information required by §63.9(b)(2) and also a signed statement indicating that affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(c) As specified in §63.9(b)(3), if the Permittee startup a new or reconstructed affected source on or after the date of publication of the final rule in the federal register, the Permittee must submit an Initial Notification not later than 120 days after its become subject to this subpart. The Initial Notification must include the information required in paragraphs (c)(1) and (2) of 40 CFR 63.7545, as applicable.

(1) If the affected source has an annual capacity factor of greater than 10 percent, then the Initial Notification must include the information required by §63.9(b).

(2) If the affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, then the Initial Notification must include the information required by §63.9(b) and a signed statement indicating that affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(d) If the Permittee is required to conduct a performance test then the Permittee must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(e) If the Permittee is required to conduct an initial compliance demonstration as specified in §63.7530(a), then the Permittee must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, the Permittee must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(l) through (9) of 40 CFR 63.7545, as applicable.

D.2.31 Recordkeeping Requirements [40 CFR Part 63.7555 and 7560]

Pursuant to 40 CFR 63.7555, the Permittee shall comply with the following recordkeeping requirements:

(a) The Permittee must keep records according to paragraphs (a)(1) through (3) of 40 CFR 63.7555.

(1) A copy of each notification and report that the Permittee submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that the Permittee submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, the Permittee must keep records according to paragraphs (b)(1) through (5) of 40 CFR 63.7555.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) The Permittee must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to the Permittee.

(d) For each boiler or process heater subject to an emission limit, the Permittee must also keep the records in paragraphs (d)(1) through (5) of 40 CFR 63.7555.

(1) The Permittee must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) The Permittee must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 1 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 5 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 2 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 6 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 3 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 7 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If the boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, the Permittee must keep the records in paragraphs (e)(1) and (2) of 40 CFR 63.7555.

(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(2) Fuel use records for the days the boiler or process heater was operating.

(f) The records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(g) As specified in §63.10(b)(1), the Permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(h) The Permittee must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Permittee can keep the records off site for the remaining 3 years.

D.2.32 Reporting Requirements [40 CFR Part 63.7550]

Pursuant to 40 CFR 63.7560, the Permittee shall comply with the following reporting requirements:

(a) The Permittee must submit each report in Table 9 to this subpart that applies to the Permittee.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), the Permittee must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of 40 CFR 63.7550.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for the affected source in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for the source in §63.7495.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in §63.7495.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the Permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of 40 CFR 63.7550.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of 40 CFR Part 63.7550.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where the Permittee is not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of 40 CFR 63.7550 and the information required in paragraphs (d)(1) through (4) of 40 CFR 63.7550. This includes periods of startup, shutdown, and malfunction.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which the Permittee deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where the Permittee is using a CMS to comply with that emission limit, operating limit, or work practice standard, the Permittee must include the information in paragraphs (c)(1) through (10) of 40 CFR 63.7550 and the information required in paragraphs (e)(1) through (12) of 40 CFR 63.7550. This includes periods of startup, shutdown, and malfunction and any deviations from the site-specific monitoring plan as required in §63.7505(d).

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If the Permittee operates a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and the Permittee intends to use a fuel other than natural gas or equivalent to fire the affected unit, then the Permittee must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of 40 CFR 7550.

D.2.33 Reporting and Recordkeeping Requirements [40 CFR Part 60.107]

Pursuant to 40 CFR 60.107, the Permittee shall comply with the following reporting and recordkeeping requirements:

(a) Each Permittee subject to Sec. 60.104(b) shall notify the Administrator of the specific provisions of Sec. 60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by Sec. 60.7(a)(3). If the Permittee elects at a later date to comply with an alternative provision of Sec. 60.104(b), then IDEM, OAQ shall be notified by the owner or operator in the report described in paragraph (c) of this section.

(b) Each Permittee subject to Sec. 60.104(b) shall record and maintain the following information:

(1) If subject to Sec. 60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to Sec. 60.105(a)(13) and Sec. 60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to Sec. 60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if Sec. 60.106(i)(12) applies.

(3) If subject to Sec. 60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each Permittee subject to Sec. 60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O_2 free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with Sec. 60.104(b)(1) is below 90 percent and above 50 vppm, as measured by the continuous monitoring system prescribed under Sec. 60.105(a)(8), or above 50 vppm, as measured by the outlet continuous monitoring system prescribed under Sec. 60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under Sec. 60.106(h);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with Sec. 60.104(b)(2) exceeds 9.8 kg SO_X per 1,000 kg coke burn-off, as measured by the daily testing prescribed under Sec. 60.106(i). The average emission rate shall be determined using the procedures specified under Sec. 60.106(i); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with Sec. 60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under Sec. 60.106(j).

(2) Any 30-day period in which the minimum data requirements specified in Sec. 60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:
- **(i) The date that the exceedance occurred;**
- **(ii) An explanation of the exceedance;**
- **(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and**
- **(iv) A description of the corrective action taken, if any.**

(4) If subject to Sec. 60.104(b)(1),
- **(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;**
- **(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;**
- **(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;**
- **(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and**
- **(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.**
- **(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.**

(5) If subject to Sec. 60.104(b)(2), for each day in which a Method 8 sample result required by Sec.60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by IDEM, OAQ.

(6) If subject to Sec. 60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by Sec. 60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by IDEM, OAQ.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the Permittee of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(e) The Permittee of an affected facility shall submit the reports required under this subpart to IDEM, OAQ semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(f) The Permittee of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

SECTION D.3 FACILITY OPERATION CONDITIONS

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

The following storage vessels:

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

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
169	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1989	113;
125	**fixed roof cone tank**	**157,000**	**6,000**	**hydrocarbon with vapor pressure of No.2 fuel oil or less**	**2005**	**015;**

D.3.12 VOC Record Keeping Requirements [326 IAC 8-4-3] [40 CFR 60.115b][40 CFR 60.110b]

(a) The Permittee shall comply with the record keeping requirements of 326 IAC 8-4-3. The following records are required for tank Nos. 18 and 24:

(1) The types of volatile petroleum liquids stored,

(2) The maximum true vapor pressure of the liquids stored, and

(3) The results of the inspections performed on the tanks.

Such records will be maintained for a period of two (2) years and shall be made available to the commissioner upon written request.

(b) Pursuant to 40 CFR Part 60.110b, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels), storage tank**s** identified as 22A **and 125** ~~is~~ **are** subject to following record keeping requirements.

The Permittee shall maintain permanent records at the source in accordance with (1) through (3) below:

(1) the dimension of the storage vessel;

(2) an analysis showing the capacity of the storage vessel; and

(3) vapor pressure of organic liquid stored in tank**s** 22A **and 125**.

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

SECTION D.4 FACILITY OPERATION CONDITIONS

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

(a) Two (2) sets of Oil/water Separators **equipped with covers for VOC control**, identified as 071;
(b) one (1) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(c) pipeline Valves - Gas, identified as 090;
(d) pipeline Valves - Light Liquid, identified as 091;
(e) pipeline Valves - Heavy Liquid, identified as 092;
(f) pipeline Valves - Hydrogen, identified as 093;
(g) open Ended Valves, identified as 094;
(h) flanges, identified as 095;
(i) pump Seals Light Liquid, identified as 096;
(j) pump Seals Heavy Liquid, identified as 097;
(k) compressor Seals - Gas, identified as 098;
(l) compressor Seals - Heavy Liquid, identified as 099;
(m) drains, identified as 100;
(n) vessel Relief Valves, identified as 101;
(o) cooling Towers, identified as 119; and
(p) process units made up of vessels, piping, exchangers, identified as PENEX.
(q) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of:
(1) pipeline Valves - Gas, identified as 090;
(2) pipeline Valves - Light Liquid, identified as 091;
(3) pipeline Valves - Heavy Liquid, identified as 092;
(4) pipeline Valves - Hydrogen, identified as 093;
(5) open Ended Valves, identified as 094;
(6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(7) flanges, identified as 095;
(8) pump Seals Light Liquid, identified as 096;
(9) pump Seals Heavy Liquid, identified as 097;
(10) compressor Seals - Gas, identified as 098;
(11) compressor Seals - Heavy Liquid, identified as 099;
(12) drains, identified as 100;
(13) vessel Relief Valves, identified as 101; and
(14) cooling Towers, identified as 119.

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

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

D.4.1 General Provisions Relating to NSPS and NESHAP [326 IAC 12-1-1] [40 CFR Part 60, Subpart A] [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

(a) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 60, Subpart GGG as an “affected facility,” except when otherwise specified in 40 CFR Part 60, Subpart GGG.

(b) The provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 63, Subpart CC as an “affected facility,” except when otherwise specified in 40 CFR Part 63, Subpart CC.

(c) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 60, Subpart QQQ as an "affected facility," except when otherwise specified in 40 CFR Part 60, Subpart QQQ.

D.4.2 Equipment Leaks of VOC in Petroleum Refineries [326 IAC 12-1-1] [40 CFR Part 60, Subpart GGG]

Pursuant to 40 CFR 60.590 and 326 IAC 12-1-1, the provisions of 40 CFR 60, Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, which are incorporated by reference as 326 IAC 12-1-1, apply only to the equipments associated with the CCR unit (listed in Section D.1)**, Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit and TGTU,** and PENEX unit because they were constructed or modified after January 4, 1983.

D.4.3 Petroleum Refineries NESHAP [326 IAC 20-1-1] [40 CFR Part 63, Subpart CC]

Pursuant to 40 CFR 63.640 and 326 IAC 20-1-1, the provisions of 40 CFR 63, Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, which are incorporated by reference as 326 IAC 20-1-1, apply to affected facilities at the source because they are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act and emit or have equipment containing or contacting benzene which is one or more of the hazardous air pollutants listed in table 1 of this subpart.

D.4.4 VOC Emissions From Petroleum Refinery Wastewater Systems [326 IAC 12-1-1] [40 CFR Part 60, Subpart QQQ]

Pursuant to 40 CFR 60.690 and 326 IAC 12-1-1, the provisions of 40 CFR 60, Subpart QQQ - Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems, which are incorporated by reference as 326 IAC 12-1-1, apply to Oil/Water Separators and associated wastewater drains because these facilities are located at a petroleum refinery and are being constructed or modified after the rule applicability date of May 4, 1987.

D.4.~~4~~**5** Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries [40 CFR 60.592] **[326 IAC 12]**

Pursuant to 40 CFR 60.592, following standards apply only to the equipment associated with the CCR unit (listed in Section D.1)**, Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit and TGTU,** and the PENEX unit:

D.4.~~5~~**6** General Standards - NESHAP for Petroleum Refineries [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

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D.4.~~6~~**7** Storage Vessel Provisions [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

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D.4.~~7~~**8** Equipment Leak Standards [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

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D.4.~~8~~**9** Alternative Means of Emission Limitation: Connectors in gas/vapor service and light liquid service [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

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D.4.~~9~~**10** Emission Averaging Provisions [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

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D.4.11 General Standards [40CFR 60.692-1] [326 IAC 12]

(a) Pursuant to 40 CFR 60.692-1(a), the Permittee shall comply with the requirements of 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2 for all facilities subject to the provisions of 40 CFR 60, Subpart QQQ as provided in 40 CFR 60.690, except during periods of startup, shutdown, or malfunction.

(b) Compliance with 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR 60.696.

(c) Permission to use alternative means of emission limitation to meet the requirements of 40 CFR 60.692-2 through 60.692-4 may be granted as provided in 40 CFR 60.694.

(d) Pursuant to 40 CFR 60.692-1(d), the following units are not subject to the control requirements of 40 CFR 60, Subpart QQQ:

(1) Stormwater sewer systems;
(2) Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater; and
(3) Non-contact cooling water systems.

The Permittee shall demonstrate compliance with the exclusions in paragraphs 40 CFR 60.692-1 (d)(1), (2), and (3) of this section as provided in 40 CFR 60.697(h), (i), and (j).

(e) The definitions in 40 CFR 60, Subpart QQQ, Section 60.691 are applicable to the Permittee.

D.4.12 Standards for Individual Drain Systems [40 CFR 60.692-2] [326 IAC 12]

Pursuant to 40 CFR 60.692-2, the Permittee shall comply with the following requirements:

(a)(1) Each drain shall be equipped with water seal controls.
(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.
(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.
(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.
(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in Sec. 60.692-6.

(b)(1) Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
(2) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
(3) Junction boxes shall be visually inspected initially and semiannually hereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.
(4) If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in Sec. 60.692-6.

(c)(1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.
(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.

(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in Sec. 60.692-6.

(d) Except as provided in paragraph (e) of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section.

(e) Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

D.4.13 Standards for Oil Water Separators [40CFR 60.692-3] [326 IAC 12]

Pursuant to 40 CFR 60.692-3, the Permittee shall comply with the following requirements:

(a) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in 40 CFR 60.693-2.

(1) The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.

(2) The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.

(3) If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.

(4) Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.

(5) When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in Sec. 60.692-6.

(b) Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph (a) of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of Sec. 60.692-5, except as provided in paragraph (c) of this section or in Sec. 60.693-2.

(c)(1) Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of paragraph (b) of this section, but shall meet the requirements of paragraph (a) of this section, or may elect to comply with paragraph (c)(2) of this section.

(2) The owner or operator may elect to comply with the requirements of paragraph (a) of this section for the existing fixed roof covering a portion of the separator tank and comply with the requirements for floating roofs in Sec. 60.693-2 for the remainder of the separator tank..

(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in Secs. 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

(e) Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph (a) of this section.

(f) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph (a) of this section, and not paragraph (b) of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

D.4.14 Standards for Aggregate Facilities [40CFR 60.692-4] [326 IAC 12]

Pursuant to 40 CFR 60.692-4, a new, modified, or reconstructed aggregate facility shall comply with the requirements of40 CFR 60.692-2 and 60.692-3.

D.4.15 Standards for Closed Vent Systems and Control Devices [40CFR 60.692-5] [326 IAC 12]

Pursuant to 40 CFR 60.692-5, the Permittee shall comply with the following requirements:

(a) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 deg.C (1,500 deg.F).

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.

(c) Flares used to comply with this subpart shall comply with the requirements of 40 CFR 60.18.

(d) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(e)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in 40 CFR 60.696.

(2) Closed vent systems shall be purged to direct vapor to the control device.

(3) A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.

(4) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(5) When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in 40 CFR 60.692-6.

D.4.16 Standards for Closed Vent Systems and Control Devices [40CFR 60.692-6] [326 IAC 12]

Pursuant to 40 CFR 60.692-6, delay of repair of facilities that are subject to 40 CFR 60, Subpart QQQ shall be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

D.4.17 Standards for Delay of Compliance [40CFR 60.692-5] [326 IAC 12]

Pursuant to 40 CFR 60.692-7, delay of compliance of modified individual drain systems with ancillary downstream treatment components shall be allowed if compliance with the provisions of 40 CFR 60, subpart QQQ cannot be achieved without a refinery or process unit shutdown. Installation of equipment necessary to comply with the provisions of 40 CFR 60, Subpart QQQ shall occur no later than the next scheduled refinery or process unit shutdown.

D.4.1~~0~~**8** Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the affected facilities and their control device.

Compliance Determination Requirements

D.4.19 Performance Test Methods and Procedures [40CFR 60.696] [326 IAC 12]

Pursuant to 40 CFR 60.696, the Permittee shall comply with the following requirements:

(a) Before using any equipment installed in compliance with the requirements of Sec. 60.692-2, Sec. 60.692-3, Sec. 60.692-4, Sec. 60.692-5, or Sec. 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(b) The Permittee of each source that is equipped with a closed vent system and control device as required in Sec. 60.692-5 (other than a flare) is exempt from Sec. 60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:
(1) Zero air (less than 10 ppm of hydrocarbon in air), and
(2) A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(c) The Permittee shall conduct a performance test initially, and at other times as requested by the Administrator, using the test methods and procedures in Sec. 60.18(f) to determine compliance of flares.

(d) After installing the control equipment required to meet Sec. 60.693-2(a) or whenever sources that have ceased to treat refinery wastewater for a period of 1 year or more are placed back into service, the owner or operator shall determine compliance with the standards in Sec. 60.693-2(a) as follows:
(1) The maximum gap widths and maximum gap areas between the primary seal and the separator wall and between the secondary seal and the separator wall shall be determined individually within 60 calendar days of the initial installation of the floating roof and introduction of refinery wastewater or 60 calendar days after the equipment is placed back into service using the following procedure when the separator is filled to the design operating level and when the roof is floating off the roof supports.

(i) Measure seal gaps around the entire perimeter of the separator in each place where a 0.32 cm (0.125 in.) diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the separator and measure the gap width and perimetrical distance of each such location.

(ii) The total surface area of each gap described in (d)(1)(i) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the wall to the seal and multiplying each such width by its respective perimetrical distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually, divide the sum for each seal by the nominal perimeter of the separator basin and compare each to the maximum gap area as specified in Sec. 60.693-2.

(2) The gap widths and total gap area shall be determined using the procedure in paragraph (d)(1) of this section according to the following frequency:

(i) For primary seals, once every 5 years.

(ii) For secondary seals, once every year.

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

D.4.~~11~~**20** Monitoring, Recordkeeping, and Implementation Plan for Emissions Averaging [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

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D.4.21 Monitoring Requirements [40CFR 60.695] [326 IAC 12]

(a) Pursuant to 40 CFR 60.695, the Permittee shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by IDEM, OAQ.

(1) Where a thermal incinerator is used for VOC emission reduction, a temperature monitoring device equipped with a continuous recorder shall be used to measure the temperature of the gas stream in the combustion zone of the incinerator. The temperature monitoring device shall have an accuracy of +/- 1 percent of the temperature being measured, expressed in deg.C, or +/- 0.5 deg.C (0.9 deg.F), whichever is greater.

(2) Where a catalytic incinerator is used for VOC emission reduction, temperature monitoring devices, each equipped with a continuous recorder shall be used to measure the temperature in the gas stream immediately before and after the catalyst bed of the incinerator. The temperature monitoring devices shall have an accuracy of +/- 1 percent of the temperature being measured, expressed in deg.C, or +/- 0.5 deg.C (0.9 deg.F), whichever is greater.

(3) Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(i) For a carbon adsorption system that regenerates the carbon bed directly onsite, a monitoring device that continuously indicates and records the volatile organic compound concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

(4) Where a flare is used for VOC emission reduction, the owner or operator shall comply with the monitoring requirements of 40 CFR 60.18(f)(2).

(b) Where a VOC recovery device other than a carbon adsorber is used to meet the requirements specified in Sec. 60.692-5(a), the owner or operator shall provide to the Administrator information describing the operation of the control device and the process parameter(s) that would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

(c) An alternative operational or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

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

D.4.~~1~~**2**2 Reporting and Record Record Keeping Requirements [326 IAC 20-10-1] [40 CFR Part 63.654, Subpart CC]

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(h) To document compliance with Condition D.4.~~11~~**20**, if the Permittee uses emissions averaging, the permittee shall keep records of all the required parameters listed in Condition D.4.~~11~~**20**.

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

D.4.23 Recordkeeping Requirements [40CFR 60.696] [326 IAC 12]

Pursuant to 40 CFR 60.696, the Permittee shall comply with the following requirements:

(a) Each Permittee of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

(b)(1) For individual drain systems subject to Sec. 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

(2) For junction boxes subject to Sec. 60.692-2, the location, date, and corrective action shall be recorded for inspections required by Sec. 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(3) For sewer lines subject to Sec. Sec. 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by Sec. Sec. 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

(c) For oil-water separators subject to Sec. 60.692-3, the location, date, and corrective action shall be recorded for inspections required by by Sec. 60.692-3(a) when a problem is identified that could result in VOC emissions.

(d) For closed vent systems subject to Sec. 60.692-5 and completely closed drain systems subject to Sec. 60.693-1, the location, date, and corrective action shall be recorded for inspections required by Sec. 60.692-5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

(e)(1) If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

(2) The reason for the delay as specified in Sec. 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.

(3) The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.

(4) The date of successful repair or corrective action shall be recorded.

(f)(1) A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.

(2) The following information pertaining to the design specifications shall be kept.

(i) Detailed schematics, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(3) The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 ^{o}C (1,500 ^{o}F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(iii) Periods when the closed vent systems and control devices required in Sec. 60.692 are not operated as designed, including periods when a flare pilot does not have a flame shall be recorded and kept for 2 years after the information is recorded.

(iv) Dates of startup and shutdown of the closed vent system and control devices required in Sec. 60.692 shall be recorded and kept for 2 years after the information is recorded.

(v) The dates of each measurement of detectable emissions required in Sec. Sec. 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.

(vi) The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.

(vii) The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.

(viii) Each Permittee of an affected facility that uses a thermal incinerator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 ^{o}C (50 ^{o}F) below the design combustion zone temperature, and shall keep such records for 2 years after the information is recorded.

(ix) Each Permittee of an affected facility that uses a catalytic incinerator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 ^{o}C (50 ^{o}F) below the design gas stream temperature, and records of all 3-hour periods during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference, and shall keep such records for 2 years after the information is recorded.

(x) Each Permittee of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(A) Each Permittee of an affected facility that uses a carbon adsorber which is regenerated directly onsite shall maintain continuous records of the volatile organic compound concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(B) If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

(g) If the Permittee elects to install a tightly sealed cap or plug over a drain that is out of active service, the owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which indicate the location of such drains.

(h) For stormwater sewer systems subject to the exclusion in Sec. 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

(i) For ancillary equipment subject to the exclusion in Sec. 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonsrate that the ancillary equipment does not come in contact with or store oily wastewater.

(j) For non-contact cooling water systems subject to the exclusion in Sec. 60.692-1(d)(3), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

(k) For oil-water separators subject to Sec. 60.693-2, the location, date, and corrective action shall be recorded for inspections required by Sec. Sec. 60.693-2(a)(1)(iii)(A) and (B), and shall be maintained for the time period specified in paragraphs (k)(1) and (2) of this section.

(1) For inspections required by Sec. 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.

(2) For inspections required by Sec. 60.693-2(a)(1)(iii)(B), two years after the information is recorded.

D.4.24 Reporting Requirements [40CFR 60.698] [326 IAC 12]

Pursuant to 40 CFR 60.698, the Permittee shall comply with the following requirements:

(a) The Permittee electing to comply with the provisions of Sec. 60.693 shall notify the Administrator of the alternative standard selected in the report required in Sec. 60.7.

(b)(1) Each Permittee of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

(2) Each Permittee of an affected facility that uses a flare shall submit to the Administrator within 60 days after initial startup, as required under Sec. 60.8(a), a report of the results of the performance test required in Sec. 60.696(c).

(c) A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to OAQ, IDEM.

(d) As applicable, a report shall be submitted semiannually to the Administrator that indicates:

(1) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal incinerator, as measured by the temperature monitoring device, is more than 28 [deg]C (50 [deg]F) below the design combustion zone temperature,

(2) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic incinerator, as measured by the temperature monitoring device, is more than 28 [deg]C (50 [deg]F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference, or,

(3) Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

(i) Each 3-hour period of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases from a carbon adsorber which is regenerated directly onsite is more than 20 percent greater than the design exhaust gas concentration level or reading.

(ii) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in Sec. 60.695(a)(3)(ii).

(e) If compliance with the provisions of this subpart is delayed pursuant to Sec. 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(a) one (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 and exhausting to stack 118;
(b) one (1) crude heater **equipped with the Low-NOx burner**, with a maximum heat input rate of 131 million British Thermal Units per hour (mmBtu/hr) of No. 6 residual oil and process gas, identified as C-II, exhausting to stack 1;
(c) one (1) unifiner heater, with a maximum heat input rate of 20 mmBtu/hr of process gas, identified as H-H5 and exhausting to stack 2;
(d) one (1) cycle oil heater, with a maximum heat input rate of 10 mmBtu/hr of process gas, identified as H-H2 and exhausting to stack 3;
(e) one (1) naphtha splitter heater, with a maximum heat input rate of 12.2 mmBtu/hr of process gas, identified as H-H3 and exhausting to stack 4;
(f) one (1) vacuum heater, with a maximum heat input rate of 14.1 mmBtu/hr of process gas, identified as V-IV and exhausting to stack 5;
(g) one (1) old Platformer heater, with a maximum heat input rate of 29 mmBtu/hr of process gas, identified as P-H1 and exhausting to stack 6;
(h) one (1) alkylation unit heater, with a maximum heat input rate of 13.2 mmBtu/hr of process gas, identified as A-H1 and exhausting to stack 7;
(i) one (1) auxiliary crude heater, with a maximum heat input rate of 10.1 mmBtu/hr of process gas, identified as C-I and exhausting to stack 11;
(j) one (1) platformer stabilizer reb, with a maximum heat input rate of 5.92 mmBtu/hr of process gas, identified as P-H2 and exhausting to stack 12;
(k) one (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;
(l) one (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and**/**or process gas, identified as B2 and exhausting to stack 13;
(m) one (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and**/**or process gas, identified as B3 and exhausting to stack 14;
(n) one (1) vacuum heater husky, with a maximum heat input rate of 6.27 mmBtu/hr of No. 6 residual oil and process gas, identified as VIII and exhausting to stack 64.
(o) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil ~~p~~Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no H_2S combustion), installed in 1945 and exhausting to stack 9.

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

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

D.5.1 Particulate Matter (PM)

Pursuant to 326 IAC 6-2-3 (Particulate Matter Emission Limitations for Sources of Indirect Heating, the PM emissions from boilers B1, B2 and B3 shall be limited to 0.40, 0.25 and 0.40 pounds per MMBtu heat input, respectively.

This limitation is based on the following equation:

$$P_T = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where: C = maximumm ground level concentration (50 µg/m3, for a period not to exceed 60 min.)

Pt = maximum allowable particulate matter (PM) emitted per MMBtu heat input

Q = total source max. indirect heater input

N = Number of stacks in fuel burning operation.

a = Plume rise factor (0.67, for Q < 1,000)

h = Stack height in feet. If a number of stacks of different heights exist, the average stack height to represent "N" stacks shall be calculated by weighing each stack height with its particulate matter emission rate as follows:

$$h = \frac{\sum_{i=1}^{N} H_i \times pa_i \times Q}{\sum_{i=1}^{N} pa_i \times Q}$$

Where: pa = The actual controlled emission rate in lb/mmBtu using the emission factor from AP-42 or stack test data.

D.5.2 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the emission units C-II, boilers Nos. 1, 2 and 3, V-IV, A-HI, H101, and V-III, when burning No. 6 residual fuel oil, shall not exceed 1.6 pounds per MMBtu heat input. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a thirty (30) day rolling weighted average.

D.5.3 No. 6 Fuel Usage [326 IAC 2-2]

The input of No. 6 fuel oil to the three boilers B1, B2, and B3, based on a maximum fuel oil sulfur content of 0.8 percent shall be limited, to 3,214.92 thousand gallons per twelve (12) consecutive month period with compliance determined at the end of each month. This usage limit is required to limit the PM10 emissions from the boilers to less than 14.49 tons per twelve (12) consecutive month period. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

D.5.4 General Provisions Relating to NESHAP [326 IAC 20-1][40 CFR Part 63, Subpart A]

The provisions of 40 CFR 63 Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the affected sources, as designated by 40 CFR 63.7506(b). The Permittee must comply with these requirements on and after the effective date of 40 CFR 63, Subpart DDDDD.

D.5.5 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]

(a) The affected sources are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters, (40 CFR 63, Subpart DDDDD), as of the effective date of 40 CFR 63, Subpart DDDDD. Pursuant to this rule, the Permittee must comply with 40 CFR 63, Subpart DDDDD on and after three years after September 13, 2004, the effective date of 40 CFR 63, Subpart DDDDD.

(b) The following emissions units comprise the affected source for the large liquid fuel subcategory:

(1) One (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8.

(2) One (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13.

(3) One (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14.

(c) The definitions of 40 CFR 63, Subpart DDDDD at 40 CFR 63.7575 are applicable to the affected source(s).

Compliance Determination Requirements

D.5.~~3~~**6** Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition D.~~4~~**5**.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 1.6 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.5.~~4~~**7** Visible Emissions Notations

(a) Visible emission notations of the boiler stacks (B1, B2 and B3) exhaust shall be performed once per shift during normal daylight operations when exhausting to the atmosphere and while combusting fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or 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) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a violation of this permit.

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

D.5.~~5~~**8** Record Keeping Requirements

(a) To document compliance with Conditions D.5.2, the Permittee shall maintain records in accordance with (1) through (6) below.
  (1) Calendar dates covered in the compliance determination period;

(2) Actual No. 6 residual fuel oil usage per month since last compliance determination period and equivalent SO_2 emissions;

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

If the fuel supplier certification is used to demonstrate compliance 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.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document compliance with Condition D.5.**47**, the Permittee shall maintain records of visible emission notations of the three boiler stacks (B1, B2 and B3) once per shift.

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

D.5.9 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters - Notification Requirements [40 CFR 63, Subpart DDDDD]

(a) Pursuant to 40 CFR 63.7545(a) and 40 CFR 63.7506(b), the Permittee shall submit an Initial Notification containing the information specified in 40 CFR 63.9(b)(2) not later than 120 days after the effective date of 40 CFR 63, Subpart DDDDD as required by 40 CFR 63.7545(b).

(b) The notification required by paragraph (a) shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

and

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

The notification requires the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Mailing Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-7882-00003
Facility: Boilers B1, B2, and B3
Parameter: No. 6 Fuel Oil Usage
Limit: The input of No. 6 fuel oil to the three boilers B1, B2, and B3, based on a maximum fuel oil sulfur content of 0.8 percent shall be limited, to 3,214.92 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

YEAR:

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

☐ No deviation occurred in this quarter.

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

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

Attach a signed certification to complete this report.

Additional Changes

1. Condition B.24(c) has been revised to reflect the correct name of the section.

B.24 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

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

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

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

2. In accordance with the credible evidence rule (62 Fed. Reg. 8314, Feb 24, 1997); Section 113(a) of the Clean Air Act, 42 U.S. C. § 7413 (a); and a letter from the United States Environmental Protection Agency (USEPA) to IDEM, OAQ dated May, 18 2004, all permits must address the use of credible evidence; otherwise, USEPA will object to the permits. The following language will be incorporated into the permit to address credible evidence:

B.25 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314]

Notwithstanding the conditions of this permit that state specific methods that may be used to demonstrate compliance with, or a violation of, applicable requirements, any person (including the Permittee) may also use other credible evidence to demonstrate compliance with, or a violation of, any term or condition of this permit.

Conclusion

The construction and operation of Distillate Desulfurization Project shall be subject to the conditions of the attached proposed Minor Source Modification No.:129-18672-00003 and Significant Permit Modification No.: 129-20112-00003.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the
Technical Support Document for a Significant Source Modification and Significant Permit Modification to a Part 70 Operating Permit

Source Name:	Countrymark Cooperative, LLP
Source Location:	1200 Refinery Road, Mount Vernon, Indiana 47620
County:	Posey
SIC Code:	2911
Operation Permit No.:	T129-7882-00003
Operation Permit Issuance Date:	July 21, 2003
Source Modification No.:	129-18672-00003
Permit Modification No.:	129-20112-00003
Permit Reviewer:	Adeel Yousuf/EVP

On December 15, 2004, the Office of Air Quality (OAQ) had a notice published in The Mount Vernon Democrat in Mt. Vernon, Indiana, stating that Countrymark Cooperative, LLP had applied for a Part 70 permit modification application relating to the construction and the operation of the distillate hydrotreating unit, gas treating system, and a new storage tank at its Mount Vernon Refinery as part of the Distillate Desulfurization Project. The notice also stated that OAQ proposed to issue a permit renewal for this operation and provided information on how the public could review the proposed Part 70 permit renewal and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit renewal should be issued as proposed.

On January 7, 2005, John Deaton, of Countrymark Cooperative, LLP submitted comments on the proposed Part 70 renewal Permit. The summary of the comments and corresponding responses is as follows (bolded language has been added and the language with a line through it has been deleted):

Comment 1

Countrymark proposes the following revision to paragraph (b) of section A.3:

(b) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no ~~H_2S~~ **sour water stripper overhead off-gas** combustion), installed in 1945 and exhausting to stack 9;

This particular point source is NOT subject to NSPS Subpart J, and therefore may continue to combust refinery fuel gas streams containing H_2S. The proposed revision reflects Countrymark's commitment to eliminate the capability of combusting a particular H_2S-laden stream in this point source, thereby establishing a reduction in potential to emit for this source.

Response 1

The descriptive information under paragraph (b) of section A.3 is being revised as requested since the FCCU Raw Oil Pre-heater is not subject to the requirements of NSPS Subpart J, and therefore can combust refinery fuel gas streams containing H_2S. However, this unit will no longer burn gas from the sour water stripper overhead, which is reflected in the emission calculations. Following change has been made as a result of this comment.

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

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

****

(b) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no ~~H_2S~~ **sour water stripper overhead off-gas** combustion), installed in 1945 and exhausting to stack 9;

Comment 2

Countrymark proposes the following revision to paragraph D.2.15:

~~During the period between 30 and 36 months after issuance of this permit, i~~ **I**n order to demonstrate compliance with condition D.2.5, ...

Condition D.2.5 specifies testing between 60 and 180 days following the effective date of becoming subject to 40 CFR 60.104 to demonstrate compliance. This timeframe is established in 40 CFR 60.8. In addition, the sources affected by this paragraph will be subject to the CEMS requirements of NSPS Subpart J, including subsequent performance tests. An additional round of testing 30 to 36 months after permit issuance should not be necessary to demonstrate compliance with condition D.2.5.

Response 2

Although it is true that the affected sources will be subject to the CEMS requirements of NSPS, Subpart J, the initial compliance testing is required under 40 CFR 60.106 for the units and can not be substituted for CEMs. IDEM, OAQ requires the time frame for the testing requirement to be placed in the Performance Testing Condition. To be consistent with the requirements of 40 CFR 60.8, the time frame for testing will be changed to "between 60 and 180 days after issuance of this permit". Following change has been made as a result of this comment.

D.2.15 Performance Testing [40 CFR 60.106]

During the period between ~~30~~ **60** and ~~36~~ **180** ~~months~~ **days** after issuance of this permit, in order to demonstrate compliance with Condition D.2.5, the Permittee shall perform H_2S testing for the CCR Platformer Heater, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2) utilizing methods as approved by the Commissioner. Testing shall be conducted in accordance with Section C- Performance Testing.

Comment 3

Countrymark proposes the following changes to D.2.33:

Delete D.2.33 as currently written. 40 CFR 60.107 refers to recordkeeping and reporting requirements for FCC SO2 emissions – Note that 60.107 contains subjected references to 60.104(b) which do not apply to Countrymark because Countrymark's FCCU catalyst regenerator is NOT subject to NSPS requirements.

D.2.33 appears to have been included to satisfy recordkeeping and reporting requirements under NSPS Subpart J. Since the requirements of 40 CFR 60.107 do not seem appropriate, Countrymark proposes to comply with the general requirements of 40 CFR 60.7 – Notification and recordkeeping.

Response 3

All the reporting and recordkeeping requirements under Condition D.2.33 pertains to the Countrymark's FCCU catalyst regenerator, however, this unit is not subject to the requirements of NSPS Subpart J. Therefore, the requirements under 40 CFR 60.107 do not apply and are being removed as requested. Following change has been made as a result of this comment.

~~D.2.33 Reporting and Recordkeeping Requirements [40 CFR Part 60.107]~~

~~Pursuant to 40 CFR 60.107, the Permittee shall comply with the following reporting and recordkeeping requirements:~~

~~(a) Each Permittee subject to Sec. 60.104(b) shall notify the Administrator of the specific provisions of Sec. 60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by Sec. 60.7(a)(3). If the Permittee elects at a later date to comply with an alternative provision of Sec. 60.104(b), then IDEM, OAQ shall be notified by the owner or operator in the report described in paragraph (c) of this section.~~

~~(b) Each Permittee subject to Sec. 60.104(b) shall record and maintain the following information:~~

~~(1) If subject to Sec. 60.104(b)(1),~~

~~(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;~~

~~(ii) Measurements obtained by supplemental sampling (refer to Sec. 60.105(a)(13) and Sec. 60.106(k)) for meeting minimum data requirements; and~~

~~(iii) The written procedures for the quality control program required by appendix F, Procedure 1.~~

~~(2) If subject to Sec. 60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if Sec. 60.106(i)(12) applies.~~

~~(3) If subject to Sec. 60.104(b)(3), data obtained from the daily feed sulfur tests.~~

~~(4) Each 7-day rolling average compliance determination.~~

~~(c) Each Permittee subject to Sec. 60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:~~

~~(1) Any 7-day period during which:~~

~~(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O_2 free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with Sec. 60.104(b)(1) is below 90 percent and above 50 vppm, as measured by the continuous monitoring system prescribed under Sec. 60.105(a)(8), or above 50 vppm, as measured by the outlet~~

~~continuous monitoring system prescribed under Sec. 60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under Sec. 60.106(h);~~

~~(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with Sec. 60.104(b)(2) exceeds 9.8 kg SO_x per 1,000 kg coke burn-off, as measured by the daily testing prescribed under Sec. 60.106(i). The average emission rate shall be determined using the procedures specified under Sec. 60.106(i); and~~

~~(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with Sec. 60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under Sec. 60.106(j).~~

~~(2) Any 30-day period in which the minimum data requirements specified in Sec. 60.104(d) are not obtained.~~

~~(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:~~

~~(i) The date that the exceedance occurred;~~

~~(ii) An explanation of the exceedance;~~

~~(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and~~

~~(iv) A description of the corrective action taken, if any.~~

~~(4) If subject to Sec. 60.104(b)(1),~~

~~(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;~~

~~(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;~~

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

~~(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and~~

~~(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.~~

~~(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.~~

~~(5) If subject to Sec. 60.104(b)(2), for each day in which a Method 8 sample result required by Sec.60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by IDEM, OAQ.~~

~~(6) If subject to Sec. 60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by Sec. 60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by IDEM, OAQ.~~

~~(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the Permittee of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data~~

~~unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.~~

~~(e) The Permittee of an affected facility shall submit the reports required under this subpart to IDEM, OAQ semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.~~

~~(f) The Permittee of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.~~

Comment 4

D.5 Facility Operation Conditions:
Please correct the following in the Facility Operation Conditions information section:

1. (b) one (1) Crude Heater equipped with low-NOx ~~bruner~~ **burner**. . .
2. (o) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no ~~H_2S~~ **sour water stripper overhead off-gas** combustion), installed in 1945 and exhausting to stack 9; (REFER TO COMMENT #1)

Response 4

Section D.5 has been revised as follows to correct the typographical errors.

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

****

(b) one (1) crude heater equipped with the Low-NOx ~~bruner~~ **burner**, with a maximum heat input rate of 131 million British Thermal Units per hour (mmBtu/hr) of No. 6 residual oil and process gas, identified as C-II, exhausting to stack 1;

****

(o) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no ~~H_2S~~ **sour water stripper overhead off-gas** combustion), installed in 1945 and exhausting to stack 9.

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

Comment 5

Part 70 Quarterly Report:

Please make the following correction to Part 70 Quarterly Report form:

The input of No. 6 fuel oil to the three boilers B1, B2, and B3 based on a maximum fuel oil sulfur content of 0.8 percent shall be limited to 3214.92 **thousand** gallons per twelve (12) consecutive month with compliance determined at the end of each month.

Response 5

Part 70 Quarterly Report form has been revised to add "thousand" as requested.

Limit: The input of No. 6 fuel oil to the three boilers B1, B2, and B3, based on a maximum fuel oil sulfur content of 0.8 percent shall be limited, to 3,214.92 **thousand** gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

Comment 6

Potential to Emit of Modification After Issuance:

Countrymark proposes the following change to Note c. at the bottom of the table on Page 8 of the Technical Support Document.

> Decrease in SO2 emissions due to elimination of ~~H_2S~~ **Sour water stripper overhead off-gas** combustion. Only refinery **fuel** gas will be combusted in this unit.

Response 6

The following revisions have been made to the Technical Support Document under the Potential to Emit section (**bolded** language has been added, the language with a ~~line~~ through it has been deleted). The OAQ prefers that the Technical Support Document reflect the permit that was on public notice. Changes to the permit or technical support material that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result of ensuring that these types of concerns are documented and part of the record regarding this permit decision.

Note c under the "Potential to Emit of Modification After Issuance" table has been revised as follows:

c. Decrease in SO_2 emissions due to elimination of ~~H_2S~~ **Sour water stripper overhead off-gas** combustion. Only refinery **fuel** gas will be combusted in this unit.

Comment 7

Part 70 Quarterly Report:

Please make the following correction to Part 70 Quarterly Report form:

> The input of No. 6 fuel oil to the three boilers B1, B2, and B3 based on a maximum fuel oil sulfur content of 0.8 percent shall be limited to 3214.92 **thousand** gallons per twelve (12) consecutive month with compliance determined at the end of each month.

Response 7

Part 70 Quarterly Report form has been revised to add "thousand" as requested.

Limit: The input of No. 6 fuel oil to the three boilers B1, B2, and B3, based on a maximum fuel oil sulfur content of 0.8 percent shall be limited, to 3,214.92 **thousand** gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

Comment 8

Technical Support Document (APPENDIX A):

Please make the following correction to Page 6 of 17 of APPENDIX A:

Sulfur content of ~~Crude~~ **FCCU Raw Oil** Heater Refinery fuel gas is 1.27% (not subject to NSPS Subpart J limit of 0.01 gr/dscf)

Response 8

Page 6 of 17 of emission calculations (Page 6 of 17) has been revised to list the correct emission unit as requested.

Sulfur content of ~~Crude~~ **FCCU Raw Oil** Heater Refinery fuel gas is 1.27% (not subject to NSPS Subpart J limit of 0.01 gr/dscf)

Upon further review, the OAQ has decided to make the following revisions to the permit (bolded language has been added, the language with a line through it has been deleted).

1. The signature blocks, P.O. box and the zip code on the cover page of the permit along with Commissioner and Governor's name have been revised to reflect the latest update.

2. Conditions B.2, B.14 and B.17 have been revised and Condition B.26 added to the permit to further address and clarify the permit term and the term of the conditions. All other Section B conditions have been re-numbered accordingly.

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

(a) This permit**, T129-7882-00003,** is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

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

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

(a) All terms and conditions of ~~previous~~ permits **established prior to T129-7882-00003 and** issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

~~by this permit.~~

(b) Provided that all terms and conditions are accurately reflected in this combined permit, all previous registrations and permits are superseded by this **combined new source review and part 70 operating** permit.

B.17 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] **[326 IAC 2-7-8(e)]**

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

(b) ~~Timely Submittal of Permit Renewal [326 IAC 2-7-4(a)(1)(D)]~~

~~(1)~~ A timely renewal application is one that is:

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

~~(B)~~ **(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.

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

(c) ~~Right to Operate After Application for Renewal [326 IAC 2-7-3]~~
If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ, takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified in writing by IDEM, OAQ, any additional information identified as being needed to process the application.

~~(d) United States Environmental Protection Agency Authority [326 IAC 2-7-8(e)]~~
~~If IDEM, OAQ fails to act in a timely way on a Part 70 permit renewal, the U.S. EPA may invoke its authority under Section 505(e) of the Clean Air Act to terminate or revoke and reissue a Part 70 permit.~~

B.26 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.

3. Condition B.21 has been updated to include a new "b" concerning modifications to a major source.

B.21 Source Modification Requirement [326 IAC 2-7-10.5] **[326 IAC 2-3-2]**

(a) A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2 and 326 IAC 2-7-10.5.

(b) Any modification at an existing major source is governed by the requirements of 326 IAC 2-3-2.

4. The emission statement rule has been revised and effective on March 27, 2004. Therefore the Emission Statement condition in this permit has been revised as follows:

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

(a) ~~The Permittee shall submit an annual emission statement certified pursuant to the requirements of 326 IAC 2-6, that must be received by July 1 of each year and must comply with the minimum requirements specified in 326 IAC 2-6-4. The annual emission statement shall meet the following requirements:~~ **Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:**

(1) Indicate estimated actual emission of **all** pollutants ~~from the source,~~ listed in ~~compliance with~~ 326 IAC 2-6**-4(a)** ~~(Emission Reporting)~~;

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant which is used only for purposes of Section 19 of this rule") from the source, for purposes of Part 70 fee assessment.

(b) The annual emission statement covers the twelve (12) consecutive month time period starting January 1 and ending December 31. The annual emission statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

The emission statement does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The annual emission statement 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.

5. Following conditions under Section 2 of the permit have been revised to list the correct rule references.

D.2.23 Monitoring, Installation, Operation, and Maintenance Requirements [40 CFR 63.75~~05~~**25**]

Pursuant to 40 CFR 63.75~~05~~**25**, the Permittee shall comply with the following requirements:

(a) If the Permittee has an applicable work practice standard for carbon monoxide, and the boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, then the Permittee must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of ~~this~~ 40 CFR 63.75~~05~~**25** by the compliance date specified in §63.7495.

****

(b) If the Permittee has an applicable opacity operating limit, then the Permittee must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of 40 CFR 63.75~~05~~**25** by the compliance date specified in §63.7495.

****

(c) If the Permittee has an operating limit that requires the use of a CMS, then the Permittee must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of 40 CFR 63.75~~05~~**25** by the compliance date specified in §63.7495.

****

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of 40 CFR 63.75~~05~~**25**.

****

(d) If the Permittee has an operating limit that requires the use of a flow measurement device, then the Permittee must meet the requirements in paragraphs (c) and (d)(1) through (4) of 40 CFR 63.75~~05~~**25**.

****

(e) If the Permittee has an operating limit that requires the use of a pressure measurement device, then the Permittee must meet the requirements in paragraphs (c) and (e)(1) through (6) of 40 CFR 63.75~~05~~**25**.

****

(f) If the Permittee has an operating limit that requires the use of a pH measurement device, then the Permittee must meet the requirements in paragraphs (c) and (f)(1) through (3) of this 40 CFR 63.75~~05~~**25**.

****

(h) If the Permittee has an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), then the Permittee must meet the requirements in paragraphs (c) and (h)(1) through (3) of 40 CFR 63.75~~05~~**25**.

****

(i) If the Permittee elects to use a fabric filter bag leak detection system to comply with the requirements of this subpart, then the Permittee must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of 40 CFR 63.75~~05~~**25**.

****

D.2.25 Continuous Compliance Requirements [40 CFR 63.75~~30~~**35**]

Pursuant to 40 CFR 63.75~~30~~**35**, the Permittee shall comply with the following requirements:

(a) The Permittee must monitor and collect data according to 40 CFR 63.75~~30~~**35** and the site-specific monitoring plan required by §63.7505(d).

****

D.2.32 Reporting Requirements [40 CFR Part 63.7550]

Pursuant to 40 CFR 63.75~~60~~**50**, the Permittee shall comply with the following reporting requirements:

****

Appendix A: Emission Calculations

Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620
Title V SSM No..: 129-18672-0003
Reviewer: Adeel Yousuf / EVP
Date: July 30, 2004

Uncontrolled Potential Emissions (tons/year)

	Emissions Generating Activity								
Pollutant	Combustion	Combustion	Combustion	Combustion	Combustion	Fugitives	Storage Tanks	Contemporaneous decreases	**TOTAL**
	Hydrotreater Units	TGTU Incinerator Process Emissions, Burner and Unscheduled downtime	Claus Unit Startup burner	Sour Flare Pilot	No. 6 Fuel Oil in Boilers	from components	710T-101 and Tank 46 *	Emission Reductions **	
	101	162	520-H-101	520-H-163	B1, B2, and B3				
PM	1.52	0.05	0.05	0.03	14.72	0.00	0.00	0.00	16.37
PM10	1.52	0.05	0.05	0.03	12.84	0.00	0.00	0.00	14.49
SO2	5.68	11.63	0.00	0.04	53.30	0.00	0.00	-33.48	37.17
NOx	6.87	0.66	0.67	0.40	66.98	0.00	0.00	-48.44	27.13
VOC	1.10	0.04	0.04	0.02	0.04	1.23	7.57	-280.28	-270.25
CO	16.75	0.55	0.56	0.33	1.51	0.00	0.00	0.00	19.70
total HAPs	0.37	0.01	0.01	0.01	3.39	0.06	0.15	-4.50	-0.49
worst case single HAP	0.359 (Hexane)	0.012 (Hexane)	0.012 (Hexane)	0.007 (Hexane)	3.243 (Hexane)	0.025 (Hexane)	0.057 (Hexane)	-1.656 (Hexane)	2.059 (Hexane)
Total emissions based on rated capacity at 8,760 hours/year.									
* VOC emissions from Tank 46 are only one-time emissions from tank cleaning.									
** Contemporaneous decreases includes emission reductions from FCCU Pre-heater H-101, Crude Heater C-II Low-Nox bruner installation, and Oil/Water separator controls.									

Controlled Potential Emissions (tons/year)

	Emissions Generating Activity								
Pollutant	Combustion	Combustion	Combustion	Combustion	Combustion	Fugitives	Storage Tanks	Contemporaneous decreases	**TOTAL**
	Hydrotreater Units	TGTU Incinerator Process Emissions, Burner and Unscheduled downtime	Claus Unit Startup burner	Sour Flare Pilot	No. 6 Fuel Oil in Boilers	from components	710T-101 and Tank 46 *	Emission Reductions **	
	101	162	520-H-101	520-H-163	B1, B2, and B3				
PM	1.52	0.05	0.05	0.03	14.72	0.00	0.00	0.00	16.37
PM10	1.52	0.05	0.05	0.03	12.84	0.00	0.00	0.00	14.49
SO2	5.68	11.63	0.00	0.04	53.30	0.00	0.00	-33.48	37.17
NOx	6.87	0.66	0.67	0.40	66.98	0.00	0.00	-48.44	27.13
VOC	1.10	0.04	0.04	0.02	0.04	1.23	7.57	-280.28	-270.25
CO	16.75	0.55	0.56	0.33	1.51	0.00	0.00	0.00	19.70
total HAPs	0.37	0.01	0.01	0.01	3.39	0.06	0.15	-4.50	-0.49
worst case single HAP	0.359 (Hexane)	0.012 (Hexane)	0.012 (Hexane)	0.007 (Hexane)	3.243 (Hexane)	0.025 (Hexane)	0.057 (Hexane)	-1.656 (Hexane)	2.059 (Hexane)
Total emissions based on rated capacity at 8,760 hours/year.									
* VOC emissions from Tank 46 are only one-time emissions from tank cleaning.									
** Contemporaneous decreases includes emission reductions from FCCU Pre-heater H-101, Crude Heater C-II Low-Nox bruner installation, and Oil/Water separator controls.									

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

A. Hydrotreater Unit Reactor (122)

Equipment ID No.	Name	Primary Fuel Type	Back up Fuel Type	Maximum Heat Input Rate (MMBtu/hr)
210-H-100	Hydrotreater Reactor Charge Heater	Refinery Fuel Gas	Natural Gas	19.25

Refinery Fuel Gas Heating Value = 861 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.022	7.6	0.170	0.744
PM10	0.022	7.6	0.170	0.744
SO_2 *	0.022	950 x %S	0.637	2.791
NOx *	0.022	0.04	0.770	3.373
VOC	0.022	5.5	0.123	0.539
CO	0.022	84	1.878	8.226
Lead	0.022	0.0005	0.000	0.000
Benzene	0.022	0.0021	0.000	0.000
Formaldehyde	0.022	0.075	0.002	0.007
Hexane	0.022	1.8	0.040	0.176
Napthalene	0.022	0.00061	0.000	0.000
Toluene	0.022	0.0034	0.000	0.000

Notes:
Sulfur content of Refinery fuel gas is 0.03% (equal to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except SO_2 and NOx.
* SO_2 emission factor is taken from EPA 450-4-90-003 and NOx emission factor 0.04lb/mmbtu is provided by the burner vendor.
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.019	7.6	0.143	0.628
PM10	0.019	7.6	0.143	0.628
SO_2	0.019	0.6	0.011	0.050
NOx *	0.019	0.04	0.770	3.373
VOC	0.019	5.5	0.104	0.455
CO	0.019	84	1.585	6.944
Lead	0.019	0.0005	0.000	0.000
Benzene	0.019	0.0021	0.000	0.000
Formaldehyde	0.019	0.075	0.001	0.006
Hexane	0.019	1.8	0.034	0.149
Napthalene	0.019	0.00061	0.000	0.000
Toluene	0.019	0.0034	0.000	0.000

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.
* NOx emission factor 0.04 lb/mmbtu is provided by the burner vendor.

Methodology
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

B. Hydrotreater Unit Stabilizer (123)

Equipment ID No.	Name	Primary Fuel Type	Back up Fuel Type	Maximum Heat Input Rate (MMBtu/hr)
210-H-101	Hydrotreater Unit Stabilizer Reboiler Heater	Refinery Fuel Gas	Natural Gas	19.94

Refinery Fuel Gas Heating Value = 861 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.023	7.6	0.176	0.771
PM10	0.023	7.6	0.176	0.771
SO_2 *	0.023	950 x %S	0.660	2.891
NOx *	0.023	0.04	0.798	3.493
VOC	0.023	5.5	0.127	0.558
CO	0.023	84	1.945	8.521
Lead	0.023	0.0005	0.000	0.000
Benzene	0.023	0.0021	0.000	0.000
Formaldehyde	0.023	0.075	0.002	0.008
Hexane	0.023	1.8	0.042	0.183
Napthalene	0.023	0.00061	0.000	0.000
Toluene	0.023	0.0034	0.000	0.000

Notes:
Sulfur content of Refinery fuel gas is 0.03% (equal to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except SO_2 and NOx.
* SO_2 emission factor is taken from EPA 450-4-90-003 and NOx emission factor 0.04lb/mmbtu is provided by the burner vendor.
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.020	7.6	0.149	0.651
PM10	0.020	7.6	0.149	0.651
SO_2	0.020	0.6	0.012	0.051
NOx *	0.020	0.04	0.798	3.493
VOC	0.020	5.5	0.108	0.471
CO	0.020	84	1.642	7.192
Lead	0.020	0.0005	0.000	0.000
Benzene	0.020	0.0021	0.000	0.000
Formaldehyde	0.020	0.075	0.001	0.006
Hexane	0.020	1.8	0.035	0.154
Napthalene	0.020	0.00061	0.000	0.000
Toluene	0.020	0.0034	0.000	0.000

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.
* NOx emission factor 0.04 lb/mmbtu is provided by the burner vendor.

Methodology
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

C. TGTU Incinerator Burner (124-2)

Equipment ID No.	Name	Primary Fuel Type	Back up Fuel Type	Maximum Heat Input Rate (MMBtu/hr)
520-H-161	TGTU Incinerator Burner	Refinery Fuel Gas	Natural Gas	1.29

Refinery Fuel Gas Heating Value = 861 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.001	7.6	0.011	0.050
PM10	0.001	7.6	0.011	0.050
SO_2 *	0.001	950 x %S	0.043	0.187
Nox	0.001	100	0.150	0.656
VOC	0.001	5.5	0.008	0.036
CO	0.001	84	0.126	0.551
Lead	0.001	0.0005	0.000	0.000
Benzene	0.001	0.0021	0.000	0.000
Formaldehyde	0.001	0.075	0.000	0.000
Hexane	0.001	1.8	0.003	0.012
Napthalene	0.001	0.00061	0.000	0.000
Toluene	0.001	0.0034	0.000	0.000

Notes:

Sulfur content of Refinery fuel gas is 0.03% (equal to NSPS Subpart J limit of 0.01 gr/dscf)

Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except SO_2 and NOx.

* SO_2 emission factor is taken from EPA 450-4-90-003.

Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.001	7.6	0.010	0.042
PM10	0.001	7.6	0.010	0.042
SO_2	0.001	0.6	0.001	0.003
Nox	0.001	100	0.126	0.554
VOC	0.001	5.5	0.007	0.030
CO	0.001	84	0.106	0.465
Lead	0.001	0.0005	0.000	0.000
Benzene	0.001	0.0021	0.000	0.000
Formaldehyde	0.001	0.075	0.000	0.000
Hexane	0.001	1.8	0.002	0.010
Napthalene	0.001	0.00061	0.000	0.000
Toluene	0.001	0.0034	0.000	0.000

Notes:

Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.

Methodology

Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

D. Crude Heater C-II Low-NOx Burners Installation

Equipment ID No.	Name	Primary Fuel Type	Back up Fuel Type	Maximum Heat Input Rate (MMBtu/hr)
C-II	Crude Heater C-II	Refinery Fuel Gas	Natural Gas	131

Refinery Fuel Gas Heating Value = 1000 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.131	7.6	0.996	4.361
PM10	0.131	7.6	0.996	4.361
SO_2 *	0.131	950 x %S	601.716	2635.515
NOx *	0.131	0.08	10.480	45.902
VOC	0.131	5.5	0.721	3.156
CO	0.131	84	11.004	48.198
Lead	0.131	0.0005	0.000	0.000
Benzene	0.131	0.0021	0.000	0.001
Formaldehyde	0.131	0.075	0.010	0.043
Hexane	0.131	1.8	0.236	1.033
Napthalene	0.131	0.00061	0.000	0.000
Toluene	0.131	0.0034	0.000	0.002

Notes:
Sulfur content of Crude Heater Refinery fuel gas is 4.835% (not subject to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except SO_2 and NOx.
* SO_2 emission factor is taken from EPA 450-4-90-003 and NOx emission factor 0.08 lb/mmbtu is provided by the burner vendor.
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.128	7.6	0.976	4.275
PM10	0.128	7.6	0.976	4.275
SO_2	0.128	0.6	0.077	0.338
NOx *	0.128	0.06	7.860	34.427
VOC	0.128	5.5	0.706	3.094
CO	0.128	84	10.788	47.252
Lead	0.128	0.0005	0.000	0.000
Benzene	0.128	0.0021	0.000	0.001
Formaldehyde	0.128	0.075	0.010	0.042
Hexane	0.128	1.8	0.231	1.013
Napthalene	0.128	0.00061	0.000	0.000
Toluene	0.128	0.0034	0.000	0.002

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.
* NOx emission factor 0.06 lb/mmbtu is provided by the burner vendor.

Methodology
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

E. FCCU Raw Oil Heater

Equipment ID No.	Name	Primary Fuel Type	Back up Fuel Type	Maximum Heat Input Rate (MMBtu/hr)
H-101	FCCU Pre-Heater H-101	Refinery Fuel Gas	Natural Gas	18.1

Refinery Fuel Gas Heating Value = 1000 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.018	7.6	0.138	0.603
PM10	0.018	7.6	0.138	0.603
SO_2 *	0.018	950 x %S	21.838	95.649
Nox	0.018	100	1.810	7.928
VOC	0.018	5.5	0.100	0.436
CO	0.018	84	1.520	6.659
Lead	0.018	0.0005	0.000	0.000
Benzene	0.018	0.0021	0.000	0.000
Formaldehyde	0.018	0.075	0.001	0.006
Hexane	0.018	1.8	0.033	0.143
Napthalene	0.018	0.00061	0.000	0.000
Toluene	0.018	0.0034	0.000	0.000

Notes:

Sulfur content of Crude Heater Refinery fuel gas is 1.27% (not subject to NSPS Subpart J limit of 0.01 gr/dscf)

Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except SO_2.

* SO_2 emission factor is taken from EPA 450-4-90-003.

Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.018	7.6	0.135	0.591
PM10	0.018	7.6	0.135	0.591
SO_2	0.018	0.6	0.011	0.047
Nox	0.018	100	1.775	7.772
VOC	0.018	5.5	0.098	0.427
CO	0.018	84	1.491	6.529
Lead	0.018	0.0005	0.000	0.000
Benzene	0.018	0.0021	0.000	0.000
Formaldehyde	0.018	0.075	0.001	0.006
Hexane	0.018	1.8	0.032	0.140
Napthalene	0.018	0.00061	0.000	0.000
Toluene	0.018	0.0034	0.000	0.000

Notes:

Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion.

Methodology

Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

F. Claus Unit Startup Burner (124-1)

Equipment ID No.	Name	Primary Fuel Type	Back up Fuel Type	Maximum Heat Input Rate (MMBtu/hr)
520-H-101	Claus Startup Burner	Natural Gas	None	1.56

Natural Gas Heating Value = 1020 BTU/Scf

Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.002	7.6	0.012	0.051
PM10	0.002	7.6	0.012	0.051
SO_2	0.002	0.6	0.001	0.004
Nox	0.002	100	0.153	0.670
VOC	0.002	5.5	0.008	0.037
CO	0.002	84	0.128	0.563
Lead	0.002	0.0005	0.000	0.000
Benzene	0.002	0.0021	0.000	0.000
Formaldehyde	0.002	0.075	0.000	0.001
Hexane	0.002	1.8	0.003	0.012
Napthalene	0.002	0.00061	0.000	0.000
Toluene	0.002	0.0034	0.000	0.000

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion.

G. Sour Flare Pilot

Equipment ID No.	Name	Primary Fuel Type	Back up Fuel Type	Maximum Heat Input Rate (MMBtu/hr)
520-H-163	Sour Flare Pilot	Natural Gas	None	0.92

Natural Gas Heating Value = 1020 BTU/Scf

Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum Rate (MMcf/hr)	Emission Factor (lb/MMcf)	Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (tons/yr)
PM	0.001	7.6	0.007	0.030
PM10	0.001	7.6	0.007	0.030
SO_2	0.001	0.6	0.001	0.002
Nox	0.001	100	0.090	0.395
VOC	0.001	5.5	0.005	0.022
CO	0.001	84	0.076	0.332
Lead	0.001	0.0005	0.000	0.000
Benzene	0.001	0.0021	0.000	0.000
Formaldehyde	0.001	0.075	0.000	0.000
Hexane	0.001	1.8	0.002	0.007
Napthalene	0.001	0.00061	0.000	0.000
Toluene	0.001	0.0034	0.000	0.000

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion.

Methodology
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

Appendix A: Emission Calculations
Oil Water Separator Emissions

Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620
Title V SPM No..: 129-20112-00003
Reviewer: Adeel Yousuf / EVP
Date: May 6, 2004

Oil Water Separator Emissions

	Surface Area, ft2	Potential VOC, ton/yr*	Control Eff.	Controlled VOC, ton/yr	Reduction, ton/yr
Old API Grit Pit	165	45.46	96	1.82	
Old API East Bay	406	111.87	96	4.47	
Old API West Bay	640	176.34	96	7.05	
New API Both Bays	800	220.43	95	11.02	
New API Slurry oil pit	104	28.66	95	1.43	
Total	**2115**	**582.76**		**25.80**	
Total Controlled		**294.55**		**14.27**	**280.28**

Notes:

Items highlighted in 'grey' are the ones which are being equipped with VOC controls

* VOC emissions were calculated using evaporation correlation in the Title V permit (T29-7882-00003).

Both "Old" and "New" API Oil Water Separators are existing sources.

Old API controls added in 2000.

New API controls will be added to comply with 40 CFR 60, Subpart QQQ in conjunction with Distillate Desulfurization Project.

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

I. SO_2 Emissions from the TGTU Incinerator (520-H-162)

TGTU Stack	Stream 166	
lb mol/hr H20	34.99	June 2003 data
lb mol/hr Total	159.25	June 2003 data
% moisture	21.97	
lb mol/hr O2	4.78	June 2003 data
lb mol/hr H2O	34.99	June 2003 data
lb mol/hr Total dry	124.26	
% O2 dry	3.85	
Flow wet, MSCFD	1,451	June 2003 data
Flow dry, MSCFD	1,132	
Flow, DSCFH	47,158	
Flow, DSCFH rounded	48,000	

SO2 Conc @ stack % O2 = SO2 Conc @ 0%O2 [20.9 - stack % O2 / 20.9 - 0% O2]

Stack % O2	3.847	
Conc @ 0 % O2	250	ppmv
Conc @ stack % O2	204	ppmv

SO2 emission rate, lb/hr = SO2 conc @ stack % O2 x MW SO2 x Flow, DSCFH x 1/386.5 x 1/1,000,000

lb mol SO2	64	
SO2 emission rate, lb/hr	**1.62**	
SO2 emission rate, ton/yr	**7.10**	

II. SO_2 Emissions when CCR is down and hydrogen is being lost to TGTU burner

TGTU Feed (design)	Stream 114	
lb Mol/hr H2S	0.57	June 2003 data
lb Mol/hr Total	114.89	June 2003 data
%H2S	0.50	
ppmv H2S	4,961	
Flow, MSCFD	1,045	June 2003 data
Flow, SCFH	43,558	
Flow, SCFH rounded	44,000	
MW H2S	34	

SO2 emission rate, lb/hr = H2S Conc x MW H2S x Flow, SCFH x 1/386.5 x 1/1,000,000 x 64 lb SO2/lb mol x 1/34 lb H2S/lb mol

SO2 emission rate, lb/hr	**36.15**	
SO2 emission rate, ton/yr	**4.34**	**(based on 240 hyr/yr)**

Note:
Emission calculation including stack parameters are provided by the source

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SSM No..: **129-18672-0003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

III. SO_2 Emissions from Sour Flare (520-H-163)

Amine Treated Rich Amine Flash Drum to Sour Flare	Stream 51	
lb Mol/hr H2S	0.00022	June 2003 data
lb Mol/hr Total	0.834	June 2003 data
%H2S	0.03	
ppm H2S	264	
Flow, MSCFD	4.88	Jan 2003 data (Sum of Streams 51 and 175)
Flow, SCFH	203	
Flow, SCFH rounded	200	
MW H2S	34	

SO2 emission rate, lb/hr = H2S Conc x MW H2S x Flow, SCFH x 1/386.5 x 1/1,000,000 x 64 lb SO2/lb mol x 1/34 lb H2S/lb mol

SO2 emission rate, lb/hr	**0.01**
SO2 emission rate, ton/yr	**0.038**

Note:
Emission calculation including stack parameters are provided by the source

Appendix A: Emission Calculations
Tank VOC Emissions - Maximum PTE

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

Tank	Product	Losses (Tons per Year)		Total VOC
Number	Stored	Working Loss	Breathing Loss	Tons/yr
710T-101	Sour Water Storage	0.17	0.0025	0.1725
510-T-101	Amine and Condensate			negl.
510-V-111	Amine and Condensate			negl.
Tank 46 *	Low sulfur diesel			7.40
Total VOC				**7.5725**

Note: Storage tank emissions are estimated using USEPA's Tanks 4.0 software program and provided by the source.
* Tank 46 is an existing tank at the source storing unleaded gasoline. This tank service is being converted from gasoline to low sulfur diesel, therefore, the VOC emissions reflect the one-time emission from cleaning Tank 46.

Appendix A: Emission Calculations
Tanks HAP and Fugitive HAP Emissions

Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620
Title V SPM No..: 129-20112-00003
Reviewer: Adeel Yousuf / EVP
Date: May 6, 2004

HAP	Vapor Mass Fraction* - Distillate	Vapor Mass Fraction* - Gasoline
Benzene	0.026	0.003
Ethylbenzene	0.002	0.000
Toluene	0.007	0.005
Xylene	0.002	0.002
Cyclohexane	0.000	0.002
n-Hexane	0.027	0.007

* - The vapor mass fraction was determined using the TANKS program using the liquid concentrations of HAPs from a Countrymark distillate and gasoline sample.

	Fugitive - Gasoline Components	Fugitive - Distillate Components	Oil/Water Separator	Tank 710T-101	Tank 46 Cleaning (one time)	Tank 22A	Total
Potential VOC Emissions	0.410	0.820	-236.63	0.175	7.4	1.26	-226.565
Potential HAP Emissions							
Benzene	0.001	0.021	-0.710	0.005	0.022	0.033	-0.627
Ethylbenzene	0.000	0.002	0.000	0.000	0.000	0.003	0.005
Toluene	0.002	0.006	-1.183	0.001	0.037	0.009	-1.128
Xylene	0.001	0.002	-0.473	0.000	0.015	0.003	-0.452
Cyclohexane	0.001	0.000	-0.473	0.000	0.015	0.000	-0.458
n-Hexane	0.003	0.022	-1.656	0.005	0.052	0.034	**-1.540**
Total Combined HAP	0.008	0.054	-4.496	0.011	0.141	0.083	**-4.200**

The fugitive component emissions are split 33%/67% between gasoline and distillate.
Gasoline speciation is used for the Oil/Water Separator emissions as worst case.

Appendix A: Emission Calculations
Natural Gas and Refinery Fuel Gas Combustion
Less than 100 MMBtu/hr

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

	Total no.	%zero	# of zero	Zero, kg/hr/source	kg/yr	% pegged at 10,000	# of pegged	kg/hr/source Pegged @10,000	kg/yr	% middle	no. of middle	Middle ppm	kg/hr/source at middle ppm	kg/yr	% low	no. of low	Low ppm	kg/hr/source at low ppm	kg/yr	total, kg/yr	total, lb/yr	VOC total, ton/yr
Valves - All	350	92.9	325	7.80E-06	21	0.4	1	0.064	753	0.4	1.4	5000	0.00131	15	6.3	22	100	7.08E-05	13	802	1769	0.88
Flanges (2.5 x components)	875	92.9	813	3.10E-07	2	0.0	0	0.085	0	0.4	4	5000	0.00177	52	6.7	59	100	1.13E-04	56	110	242	0.12
Pump seals - All	38	78.1	30	2.40E-05	6	0.5	0.2	0.074	118	1.1	0.4	5000	0.00870	31	20.3	8	100	8.00E-04	52	206	455	0.23
Other - All	2	100	2	4.00E-06	0	0	0	0.073	0	0	0	5000	0.00020	0	0	0	100	1.99E-05	0	0	0	0.0001
Compressor Seals	0	100	0	4.00E-06	0	0	0	0.073	0	0	0	5000	0.00020	0	0	0	100	1.99E-05	0	0	0	
Vessel Relief Valves	0	100	0	4.00E-06	0	0	0	0.073	0	0	0	5000	0.00020	0	0	0	100	1.99E-05	0	0	0	
																					Total	**1.23**

Notes:
Component count estimated at 2 x Crude Unit component count
EPA Correlation Method - Refinery Factors
Zero, middle and low ppm ranges %'s based on 3rd and 4th quarter 2002 monitoring program results.

Appendix A: Emission Calculations
FCCU Preheater SO_2 Emission Reduction

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Posey, IN 47620**
Title V SPM No..: **129-20112-00003**
Reviewer: **Adeel Yousuf / EVP**
Date: **May 6, 2004**

FCCU Raw Oil PreHeater H-101 - Emission Reductions

Calculated 2003 Emissions

Point No.	Point	Rated Duty mmbtu/hr	MMCF Burned	Em Factor (multiply by %S)	%S	Emission Factor SO2*	SO2 ton/yr
009	FCCU Preheater	18.1	92.10	950.0	3.63	3447.2	158.742

Calculated 2002 Emissions

009	FCCU Preheater	18.1	73	950.0	2.87	2726.6	99.521

Average of Calculated 2002 & 2003 Emissions

009	FCCU Preheater	18.1	82.55	950.0	3.25	3086.88	129.13

Calculated Future Potential to Emit

009	FCCU Preheater	18.1	158.56	950.0	1.27	1206.5	95.649

Net Change in Emissions: Future Potential - Past Actual

Point No.	Point	Rated Duty mmbtu/hr	MMCF Burned	Em Factor (multiply by %S)	%S	Emission Factor SO2*	SO2 ton/yr
009	FCCU Preheater	18.1					**-33.483**

Emission calculations are provided by the source.
This existing emission unit will no longer comubs H_2S from the Sour Water Stripper system.

Appendix A: Emission Calculations
Crude Heater C-11 NOx Emission Reduction

Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620
Title V SPM No..: 129-20112-00003
Reviewer: Adeel Yousuf / EVP
Date: May 6, 2004

Crude Heater C-II - Emission Reductions

Calculated 2003 Emissions

Point No.	Point	Rated Duty mmbtu/hr	MMCF Burned	NOX Emission Factor	NOx ton/yr
001	Crude Heater C-II	131	581.16	280	81.362

Calculated 2002 Emissions

001	Crude Heater C-II	131	766.52	280	107.313

Average of Calculated 2002 & 2003 Emissions

001	Crude Heater C-II	131	673.84	280	94.338

* Emission Factor Units - lb/MMCF

Calculated Future Potential to Emit

001	Crude Heater C-II	131	1147.56	0.08	45.902

* Emission Factor Units - lb/MMCF

Net Change in Emissions: Future Potential - Past Actual

Point No.	Point	Rated Duty mmbtu/hr	MMCF Burned	NOX Emission Factor	NOx ton/yr
001	Crude Heater C-II	131			-48.435

Emission calculations are provided by the source.
NOx emissions are decreasing as a result of installation of low NOx burner.

Appendix A: Emission Calculations
Oil Water Separator Emissions

Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620
Title V SPM No..: 129-20112-00003
Reviewer: Adeel Yousuf / EVP
Date: May 6, 2004

Boilers B1, B2, & B3 - Emission Increase

Existing boilers B1, B2, and B3 at the refinery combust refinery fuel gas as a primary fuel, however, the emission units associated with the Distillate Desulfurization Project will consume some of the refinery fuel gas, therefore, resulting in fuel imbalance for the three boilers. In order to compensate for this fuel imbalance, Countrymark will be burning more natural gas and/or No. 6 fuel oil. Although the source is allowed to combust No. 6 fuel oil in the three boilers in unlimited quantities as permitted in the original Title V permit, the increase in emission is an indirect result of the Distillate Desulfurization Project; therefore the emissions are included in the net emission analysis and the evaluation of PSD significant levels as part of the project.

Past Actual Emissions (2002 and 2003)

Calculated 2003 Emissions (Fuel Gas)

Point No.	Point	Rated Duty mmbtu/hr	MMCF Burned	Em Factor (multiply by %S)	%S	Emission Factor SO2*	SO2 ton/yr	NOX Emission Factor	NOx ton/yr	PM10 Emission Factor*	PM10 ton/yr	PT Emission Factor*	PT ton/yr
008	No. 1 Boiler	52	114.24	950.0	1.7924	1702.756	97.261	100	5.712	7.6	0.434	7.6	0.434
013	No. 2 Boiler	65	171.35	950.0	1.7924	1702.756	145.884	100	8.568	7.6	0.651	7.6	0.651
014	No. 3 Boiler	52	285.59	950.0	1.7924	1702.756	243.145	100	14.280	7.6	1.085	7.6	1.085
		Sub-Total	571.18				486.29		28.56		2.17		2.17
			56.16456 mmBTU/hr (average)										

Calculated 2003 Emissions (using 2003 Fuel Oil Usage Data)

Point No.	Point	Rated Duty mmbtu/hr	1000 gallons burned	Em Factor (multiply by %S)	%S	Emission Factor x %S*	SO2 ton/yr	NOX Emission Factor*	NOx ton/yr	PM10 Emission Factor	PM10 ton/yr	PT Emission Factor*	PT ton/yr
008	No. 1 Boiler	52	146.244	157.0	0.73	114.61	8.381	55	4.022	10.015	0.732	11.43	0.836
013	No. 2 Boiler	65	365.61	157.0	0.73	114.61	20.951	55	10.054	10.015	1.831	11.43	2.089
014	No. 3 Boiler	52	219.366	157.0	0.73	114.61	12.571	55	6.033	10.015	1.098	11.43	1.254
		Sub-Total	731.22				41.90		20.11		3.66		4.18
			12.50102 mmBTU/hr (average)										
		Total 2003 Emissions					528.19		48.67		5.83		6.35

Calculated 2002 Emissions (Fuel Gas)

Point No.	Point	Rated Duty mmbtu/hr	MMCF Burned	Em Factor (multiply by %S)	%S	Emission Factor SO2*	SO2 ton/yr	NOX Emission Factor	NOx ton/yr	PM10 Emission Factor*	PM10 ton/yr	PT Emission Factor*	PT ton/yr
008	No. 1 Boiler	52	88.83	950.0	1.01	955.1567	42.423	100	4.442	7.6	0.338	7.6	0.338
013	No. 2 Boiler	65	133	950.0	1.01	955.1567	63.637	100	6.663	7.6	0.506	7.6	0.506
014	No. 3 Boiler	52	222.08	950.0	1.01	955.1567	106.061	100	11.104	7.6	0.844	7.6	0.844
		Sub-Total	444.16				212.12		22.21		1.69		1.69
			50.7032 mmBTU/hr (average)										

Appendix A: Emission Calculations
Oil Water Separator Emissions

Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620
Title V SPM No..: 129-20112-00003
Reviewer: Adeel Yousuf / EVP
Date: May 6, 2004

Calculated 2002 Emissions (using 2002 Fuel Oil Usage Data)

Point No.	Point	Rated Duty mmbtu/hr	1000 gallons burned	Em Factor (multiply by %S)	%S	Emission Factor x %S*	SO2 ton/yr	NOX Emission Factor*	NOx ton/yr	PM10 Emission Factor	PM10 ton/yr	PT Emission Factor*	PT ton/yr
008	No. 1 Boiler	52	77.658	157.0	0.73	114.61	4.450	55	2.136	10.015	0.389	11.43	0.444
013	No. 2 Boiler	65	194.145	157.0	0.73	114.61	11.125	55	5.339	10.015	0.972	11.43	1.110
014	No. 3 Boiler	52	116.487	157.0	0.73	114.61	6.675	55	3.203	10.015	0.583	11.43	0.666
		Sub-Total	388.29				22.25		10.68		1.94		2.22
			6.638248 mmBTU/hr (average)										
		Total 2002 Emissions					234.37		32.89		3.63		3.91
	Average of 2002 and 2003 Emissions (Past Actual)						381.28		40.78		4.73		5.13
	Total - Future Potential Emissions						434.58		107.75		17.58		19.85

Note: Future actual is provided by the source based on the calculation where maximum amount of No. 6 fuel oil can be burned while keeping the PM10 emissions below the PSD significant levels, i.e. less than 15 tons per year for the entire modification. The source will limit the additional usage of No. 6 fuel oil to less than 3,214.92 gallons per year for the three boilers, therefore, render the requirements of 326 IAC 2-2 (PSD) not applicable.

Net Change in Emissions: Future Potential - Past Actual

Point No.	Point	Rated Duty mmbtu/hr	1000 gallons burned	Em Factor (multiply by %S)	%S	Emission Factor x %S*	SO2 ton/yr	NOX Emission Factor*	NOx ton/yr	PM10 Emission Factor	PM10 ton/yr	PT Emission Factor*	PT ton/yr
008	No. 1 Boiler	52											
013	No. 2 Boiler	65	Aggregate change in emissions ---------->				**53.30**		66.98		12.84		14.72
014	No. 3 Boiler	52											

Fuel Gas Emission Factors
* Emission Factor Units - lb/MMCF
Emission Factor Source - AP-42 Section 1.4 7/98 natural gas, except SO2 - AIRS for refinery fuel gas

Fuel Oil Emission Factors
* Emission Factor Units - lb/1000 gallon
Emission Factor Source - AP42 Section 1.3, 9/98
PM emission factor 9.19(S) + 3.22 +1.5 = 11.43
PM10 emission factor 7.17[1.12(S) + 0.37] +1.5 = 10.015

Total Increase in HAP emissions as a result of additional usage of No. 6 fuel oil (Future Potential)

Pollutant	tons per year *
Lead	0.001
Benzene	0.004
Formaldehyde	0.135
Hexane	3.243
Naphthalene	0.001
Toluene	0.006

Total HAPs: 3.390

Note: Future actual of HAPs is provided by the source based on the calculation where maximum amount of No. 6 fuel oil can be burned while keeping the PM10 emissions below the PSD significant levels, i.e. less than 15 tons per year for the entire modification. HAPs emissions above reflect the emissions as a result of burning 3,214.92 gallons of No. 6 fuel oil annually. The source will limit the additional usage of No. 6 fuel oil to less than 3,214.92 gallons per year for the three boilers, therefore, render the requirements of 326 IAC 2-2 (PSD) not applicable.