INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

TO: Interested Parties / Applicant

DATE: June 26, 2009

RE: Countrymark Cooperative, LLP / 129-28028-00003

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

Notice of Decision – Approval

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

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

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

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

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

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

Enclosures
FNPER-AM.dot12/3/07

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Mr. Jim Pankey
Countrymark Cooperative, LLP
1200 Refinery Rd
Mount Vernon, IN 47620

June 26, 2009

Re: 129-28028-00003
Administrative Amendment to
Part 70 Renewal No.: T129-7882-00003

Dear Mr. Pankey:

Countrymark Cooperative, LLP was issued a Part 70 Operating Permit Renewal on February 28, 2008 for a stationary petroleum refinery source. A letter requesting changes to this permit was received on May 29, 2009. Pursuant to the provisions of 326 IAC 2-7-11(a)(7), an administrative amendment to this permit is hereby approved as described in the attached Technical Support Document.

The amendment consists of revising the descriptive information of the existing emission units in the permit.

All other conditions of the permit shall remain unchanged and in effect. For your convenience, the entire Part 70 Operating Permit as amended has been provided with this letter.

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 Mehul Sura, OAQ, 100 North Senate Avenue, MC 61-53, Room 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Mehul Sura or extension (3-6868), or dial (317) 233-6868.

Sincerely,

Chrystal A. Wagner, Section Chief
Permits Branch
Office of Air Quality

Attachments:
Updated Permit
Technical Support Document

mns

cc: File – Posey County
Posey Health Department
U.S. EPA, Region V
Southwest Regional Office
Compliance and Enforcement Managers
Compliance Data Section
Permits Administration and Support

Pat Sorensen
Environmental Resources Management
11350 North Meridian Street, Suite 320
Carmel, IN 46032

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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 No.:	129-17940-00003, issued on November 24, 2003
Significant Permit Modification No.:	129-20112-00003, issued on March 21, 2005
Administrative Amendment No.:	129-20343-00003, issued on March 30, 2005
Significant Permit Modification No.:	129-21251-00003, issued on August 15, 2005
Significant Permit Modification No.:	129-23090-00003, issued on January 30, 2007
Significant Permit Modification No.:	129-24761-00003, issued on December 17, 2007
Significant Permit Modification No.:	129-26980-00003, issued on January 27, 2009

Administrative Amendment No. 129-28028-00003	
Issued by: Chrystal A. Wagner, Section Chief Permits Branch Office of Air Quality	Issuance Date: June 26, 2009 Expiration Date: July 21, 2008

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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.

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 have been 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; Under 40 CFR 63, Subpart R, this facility is considered an existing bulk gasoline terminal.

(b) One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as 500-H101 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 500V-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; Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

(d) The following storage vessels:

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
1	fixed roof cone tank	404,418	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	075;
2	fixed roof cone tank	404,502	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	076;
3	fixed roof cone tank	404,334	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	077;
4	fixed roof cone tank	118,272	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	018;
5	fixed roof cone tank	120,456	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	019;
6	fixed roof cone tank	120,456	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	020;
7	fixed roof cone tank	126,000	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	078;
8	fixed roof cone tank	126,000	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	079;
9	fixed roof cone tank	204,204	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	023;
10	fixed roof cone tank	121,590	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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 naptha,	1988	40 CFR Part 60, Subpart Kb	082;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
15	fixed roof cone tank	24,654	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1941	-	083;
17	fixed roof cone tank	997,584	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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	40 CFR Part 60, Subpart Kb	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	40 CFR 63, Subpart CC	120;
22B	fixed roof cone tank/insulated/ heated cone tank	1,050,000	16,800	Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate,	2006	-	127;
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	40 CFR Part 60, Subpart Kb	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 naptha,	1946	-	085;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
34	fixed roof cone tank	984,480	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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 Distillate,	1946	-	046;
36	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,261,954	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of jet kerosene,	1946	-	047;
37	fixed roof cone tank	2,247,126	210,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1946	-	048;
38	fixed roof cone tank	2,248,386	210,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1948	-	049;;
39	fixed roof cone tank	2,250,234	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1948	-	050;
40	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,222,388	336,000	RVP 15 Gasoline,	1949	-	051;
41	fixed roof cone tank/internal floating roof tank,/mechanical 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 naptha,	1950	-	053;
43	fixed roof cone tank	2,254,098	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
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/mechanical primary seal	3,402,000	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of Distillate,	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	40 CFR Part 60, Subpart K	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 naptha,	1976	40 CFR Part 60, Subpart K	063;
53	fixed roof cone tank	16,926	168,000	Ethanol,	1985	40 CFR Part 60, Subpart Kb	086;
54	fixed roof cone tank	16,926	168,000	Ethanol,	1985	40 CFR Part 60, Subpart Kb	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;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
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	40 CFR Part 60, Subpart Kb	103;
160	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	40 CFR Part 60, Subpart Kb	104;
161	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	40 CFR Part 60, Subpart Kb	105;
162	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	40 CFR Part 60, Subpart Kb	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	40 CFR Part 60, Subpart Kb	109;
166	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	40 CFR Part 60, Subpart Kb	110;
167	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	40 CFR Part 60, Subpart Kb	111;
168	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	40 CFR Part 60, Subpart Kb	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	40 CFR Part 60, Subpart Kb	113;
125	fixed roof cone tank	157,000	6,000	hydrocarbon with vapor pressure of No.2 fuel oil or less	2005	-	015;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
173	fixed roof cone tank/insulated/ heated cone tank	1,050,000	16,800	Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate,	2006	-	128;
174	Fixed roof cone tank/insulated/ heated cone tank	1,050,000	16,800	Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate,	2007	-	129

(e) One (1) Main Refinery Flare, identified as 700-V101 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 replaced in 2006 and exhausting to stack 118;

Under 40 CFR Part 60, Subpart Ja (currently under stay) the Main Refinery Flare is considered an affected facility.

(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 400-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 900-H1 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 200-H4 with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950, approved to be modified in 2007, and exhausting to stack 5;

(k) One (1) Old Platformer heater, identified as Naphtha Splitter Reboiler 900-H2, 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 100-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 200-H1 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 300-H4 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 200-H3 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; Under 40 CFR 63, Subpart UUU, process vents on the CCR are considered affected sources at a petroleum refinery.

(t) Two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071; Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected sources at a petroleum refinery.

(u) one (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;

(v) Pipeline Valves - Gas, identified as 090; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(w) Pipeline Valves - Light Liquid, identified as 091; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(x) Pipeline Valves - Heavy Liquid, identified as 092; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(y) Pipeline Valves - Hydrogen, identified as 093; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(z) Open Ended Valves, identified as 094; Under 40 CFR 60, Subpart GGG, open-ended valves are considered affected sources at a petroleum refinery.

(aa) Flanges, identified as 095; Under 40 CFR 60, Subpart GGG, the flanges are affected considered sources at a petroleum refinery.

(bb) Pump Seals Light Liquid, identified as 096; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(cc) Pump Seals Heavy Liquid, identified as 097; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(dd) Compressor Seals - Gas, identified as 098; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ee) Compressor Seals - Heavy Liquid, identified as 099; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ff) Drains, identified as 100.

(gg) Vessel Relief Valves, identified as 101; Under 40 CFR 60, Subpart GGG, pressure relief devices are considered affected sources at a petroleum refinery.

(hh) Cooling Towers, identified as 119; and

(ii) Process units made up of vessels, piping, exchangers, identified as PENEX. Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery.

(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: Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

(1) One (1) Claus Unit Startup burner (SRU 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 (Claus Furnace 520-H-102), 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: Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery. Under 40 CFR 63, Subpart CC, equipment leaks from storage vessels and equipment leaks associated with a bulk gasoline terminal are considered affected sources.
(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.

(nn) One (1) Vacuum heater, identified as 200-H6, with a maximum heat input rate of 5.49 mmBtu/hr, combusting refinery fuel gas and natural gas as a backup, installed in 2005 and exhausting to stack 126.

(oo) One (1) no. 4 boiler, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131.

Under the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Dc), the boiler B4, is considered a new source.

Under the Standards of Performance for Petroleum Refineries [40 CFR Part 60, Subpart J], the boiler B4, is considered a new source.

(pp) One (1) fixed roof, cone tank, internal floating roof, identified as Tank No. 175, with a capacity of 2,310,000 gallons and a maximum withdrawal rate of 210,000 gallons per hour of petroleum with vapor pressure of 13 RVP gasoline or less and exhausting to stack 130 (start construction in second quarter of 2007 and to be completed by February 2008);

Under the Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 CFR Part 60, Subpart Kb], the Tank No. 175, is considered a new source.

(qq) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja (currently under stay) the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGGa, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

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]

(d) 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, 129-7882-00003, 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 Term of Conditions [326 IAC 2-1.1-9.5]

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

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

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

B.4 Enforceability [326 IAC 2-7-7]

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

B.5 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 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 the "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. One (1) certification may cover multiple forms in one (1) submittal.

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

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

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. 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 no later than July 1 of each year to:

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

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

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

B.10 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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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

(b) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions or potential to emit. The PMPs do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.11 Emergency Provisions [326 IAC 2-7-16]

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

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

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

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

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

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

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or
Telephone Number: 317-233-0178 (ask for Compliance Section)
Facsimile Number: 317-233-6865

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

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

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require 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) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(9) be revised in response to an emergency.

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

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

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report. Any emergencies that have been previously reported pursuant to paragraph (b)(5) of this condition and certified by a "responsible official" need only referenced by the date of the original report.

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

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

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

(b) 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) 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).

(2) 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.

(3) 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.

(4) 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.

(5) 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).

(6) 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 Individual Facilities (Plant 1)

(7) 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.

(8) 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.

(9) 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.

(10) 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.

(11) 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).

(12) 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.

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

(a) All terms and conditions of permits established prior to 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.14 Termination of Right to Operate [326 IAC 2-7-10] [326 IAC 2-7-4(a)]

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

B.15 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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require 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
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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

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

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

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified 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] [40 CFR 72]

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

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

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

Any such application shall be certified by 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.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 limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

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

and

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

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

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

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

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

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require 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 emissions increases and decreases at 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.

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

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

(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] [IC 13-17-3-2]

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

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

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

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

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

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

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

The application which shall be submitted by the Permittee does require 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] [326 IAC 1-1-6]

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

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

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

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

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

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

The Permittee shall not operate an incinerator or incinerate any waste or refuse except as provided in 326 IAC 4-2 and 326 IAC 9-1-2.

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

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

C.6 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

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

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

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

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

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-52 IGCN 1003
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

C.7 Performance Testing [326 IAC 3-6]

(a) All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue

MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

Compliance Requirements [326 IAC 2-1.1-11]

C.8 Compliance Requirements [326 IAC 2-1.1-11]

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

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

C.9 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance. For new units, the monitoring and record keeping shall begin upon initial startup. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

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

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

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

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

C.10 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment.

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

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

(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

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

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

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

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).

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

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment.

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

(c) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, a calibrated backup CEMS shall be brought online within four (4) hours of shutdown of the primary CEMS, and shall be operated until such time as the primary CEMS is back in operation.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 63.1572 (b).

C.12 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60 Appendix B, 40 CFR 63, or other approved methods as specified in this permit.

C.13 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

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

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

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

C.14 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

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

within ninety (90) days after the date of issuance of this permit.

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

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level.
[326 IAC 1-5-3]

C.15 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.16 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) Upon detecting an excursion or exceedance, the Permittee shall restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Corrective actions may include, but are not limited to, the following:

(1) initial inspection and evaluation;

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

(3) any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

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

(1) monitoring results;

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

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

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

(e) The Permittee shall maintain the following records:

(1) monitoring data;

(2) monitor performance data, if applicable; and

(3) corrective actions taken.

C.17 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

C.18 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 emissions of all pollutants listed in 326 IAC 2-6-4(a);

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

The statement must be submitted to:

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

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

(b) The 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.19 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) Records of all required 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) If there is a “project” (as defined in 326 IAC 2-2-1 (qq)) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:

(1) Prior to commencing the construction of the “project” (as defined in 326 IAC 2-2-1(qq)) at an existing emissions unit, document and maintain the following records:
(A) A description of the project;
(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project;
(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:
(i) Baseline actual emissions;
(ii) Projected actual emissions;
(iii) Amount of emissions excluded under section 326 IAC 2-2-1(rr)(2)(A)(iii); and
(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(2) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(3) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption

of regular operations after the change if the project increases the design capacity or the potential to emit that regulated NSR pollutant at the emissions unit.

C.20 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. 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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, on or before the date it is due.

(d) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(e) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period. Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

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

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

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

(g) The report for project at an existing emissions unit shall be submitted within sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (c)(2) and (3) in Section C- General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee deems fit to include in this report,

Reports required in this part shall be submitted to:

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

(h) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

Stratospheric Ozone Protection

C.21 Compliance with 40 CFR 82 and 326 IAC 22-1

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

(a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

(b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

(c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

SECTION D.1 FACILITY OPERATION CONDITIONS

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

(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; Under 40 CFR 63, Subpart R, this facility is considered an existing bulk gasoline terminal.

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

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

D.1.1 General Provisions Relating to HAPs [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

The provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in Table 1 of 40 CFR Part 63, Subpart R (pursuant to 40 CFR Part 63.420(i) and 63.650, the loading rack is subject to only following sections of subpart R: 63.421, 63.422 (a) through (c), 63.425 (a) through (c) and (e) through (h), 63.427 (a) & (b), and 63.428(b), (c), (g)(1), and (h) (1) through (3)).

D.1.2 Gasoline Distribution Facilities NESHAP [326 IAC 20-10-1] [40 CFR 63, Subpart R]

Pursuant to 40 CFR Part 63.420(i) and 63.650 (Subpart CC), only the partial provisions of 40 CFR 63, Subpart R - National Emission Standards for Gasoline Distribution Facilities, which are incorporated by reference as 326 IAC 20-10-1, apply to the truck loading rack and flare . These provisions include: 63.421, 63.422 (a) through (c), 63.425 (a) through (c) and (e) through (h), 63.427 (a) & (b), and 63.428(b), (c), (g)(1), and (h) (1) through (3). A copy of this rule is attached.

D.1.3 Standards for Volatile Organic Compound (VOC) Emissions from Loading Racks [40 CFR 63.422]

Pursuant to 40 CFR 63.422, the following shall apply to the loading rack, identified as Loading Rack:

(a) Pursuant to 40 CFR 63.422, the following shall apply to the gasoline loading rack (LOAD):

(1) The Permittee shall comply with the requirements in 40 CFR 60.502 except for paragraphs (b), (c), and (j) of that section.

(2) Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded.

(3) The Permittee shall comply with 40 CFR 60.502(e) as follows:

40 CFR 60.502(e)(5) is changed to read: The Permittee shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

(i) The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e);

(ii) For each gasoline cargo tank failing the test in 40 CFR 63.425 (f) or (g) at the facility, the cargo tank either:

(A) Before repair work is performed on the cargo tank, meets the test requirements in 40 CFR 63.425 (g) or (h), or

(B) After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425 (g) or (h), subsequently passes the annual certification test described in 40 CFR 63.425(e).

D.1.4 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 Truck loading rack, identified as Loading Rack, and any control devices.

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

D.1.5 Performance Testing [40 CFR 63.425]

(a) An initial performance test on the loading rack flare was conducted on August 21, 1998 and report was submitted to IDEM, OAQ on September 26, 1998.

(b) If a flare is used to control emissions, and emissions from this device cannot be measured using the test methods and procedures in 40 CFR 60.503, the provisions of 40 CFR 63.11(b) shall apply.

(c) Annual certification test.
The annual certification test for gasoline cargo tanks shall consist of the following test methods and procedures:

(1) Method 27, appendix A, 40 CFR part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 mm H_2O (18 in. H_2O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2O (6 in. H_2O), gauge. The maximum allowable pressure and vacuum changes () p,) v) are as shown in the second column of Table 2 of this paragraph.

(2) Pressure test of the cargo tank's internal vapor valve as follows:

(i) After completing the tests under paragraph (e)(1) of this condition, use the procedures in Method 27 to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge. Close the tanks internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

(ii) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

(d) Leak detection test.
The leak detection test shall be performed using Method 21, appendix A, 40 CFR part 60, except omit section 4.3.2 of Method 21. A vapor-tight gasoline cargo tank shall have no leaks at any time when tested according to the procedures in this paragraph.

(1) The leak definition shall be 21,000 ppm as propane. Use propane to calibrate the instrument, setting the span at the leak definition. The response time to 90 percent of the final stable reading shall be less than 8 seconds for the detector with the sampling line and probe attached.

(2) In addition to the procedures in Method 21, include the following procedures:

(i) Perform the test on each compartment during loading of that compartment or while the compartment is still under pressure.

(ii) To eliminate a positive instrument drift, the dwell time for each leak detection shall not exceed two times the instrument response time. Purge the instrument with ambient air between each leak detection. The duration of the purge shall be in excess of two instrument response times.

(iii) Attempt to block the wind from the area being monitored. Record the highest detector reading and location for each leak.

(e) Nitrogen pressure decay field test.
For those cargo tanks with manifolded product lines, this test procedure shall be conducted on each compartment.

(1) Record the cargo tank capacity.
Upon completion of the loading operation, record the total volume loaded. Seal the cargo tank vapor collection system at the vapor coupler. The sealing apparatus shall have a pressure tap. Open the internal vapor valve(s) of the cargo tank and record the initial headspace pressure. Reduce or increase, as necessary, the initial headspace pressure to 460 mm H_2O (18.0 in. H_2O), gauge by releasing pressure or by adding commercial grade nitrogen gas from a high pressure cylinder capable of maintaining a pressure of 2,000 psig.

(i) The cylinder shall be equipped with a compatible two-stage regulator with a relief valve and a flow control metering valve. The flow rate of the nitrogen shall be no less than 2 cfm. The maximum allowable time to pressurize cargo tanks with headspace volumes of 1,000 gallons or less to the appropriate pressure is 4 minutes. For cargo tanks with a headspace of greater than 1,000 gallons, use as a maximum allowable time to pressurize 4 minutes or the result from the equation below, whichever is greater.
$T = V_h \times 0.004$

where: T = maximum allowable time to pressurize the cargo tank, min;
V_h = cargo tank headspace volume during testing, gal.

(2) It is recommended that after the cargo tank headspace pressure reaches approximately 460 mm H_2O (18 in. H_20), gauge, a fine adjust valve be used to adjust the headspace pressure to 460 mm H_2O (18.0 in. H_2O), gauge for the next 30 ± 5 seconds.

(3) Reseal the cargo tank vapor collection system and record the headspace pressure after 1 minute. The measured headspace pressure after 1 minute shall be greater than the minimum allowable final headspace pressure (P_F) as calculated from the following equation:

$$P_F = 18\left(\frac{(18 - N)}{18}\right)^{\left(\frac{V_s}{5(V_h)}\right)}$$

where: (P_F) = Minimum allowable final headspace pressure, in. H_2O, gauge;
V_s = total cargo tank shell capacity, gal;
V_h = cargo tank headspace volume after loading, gal;
18.0 = initial pressure at start of test, in. H_2O, gauge;

N = 5-minute continuous performance standard at any time from the third column of Table 2 of 40 CFR 63.425(e)(i), inches H_2O.

(4) Conduct the internal vapor valve portion of this test by repressurizing the cargo tank headspace with nitrogen to 460 mm H_2O (18 in. H_2O), gauge. Close the internal vapor valve(s), wait for 30 ± 5 seconds, then relieve the pressure downstream of the vapor valve in the vapor collection system to atmospheric pressure. Wait 15 seconds, then reseal the vapor collection system. Measure and

record the pressure every minute for 5 minutes. Within 5 seconds of the pressure measurement at the end of 5 minutes, open the vapor valve and record the headspace pressure as the “final pressure."

(5) If the decrease in pressure in the vapor collection system is less than at least one of the interval pressure change values in Table 3 of this paragraph, or if the final pressure is equal to or greater than 20 percent of the 1-minute final headspace pressure determined in the test in paragraph (g)(3) of this condition, then the cargo tank is considered to be a vapor-tight gasoline cargo tank.

(f) Continuous performance pressure decay test.
The continuous performance pressure decay test shall be performed using Method 27, appendix A, 40 CFR Part 60. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure (P_i) shall be 460 mm H_2O (18 in. H_2O), gauge. The maximum allowable 5-minute pressure change (Up) which shall be met at any time is shown in the third column of Table 2 of 40 CFR 63.425(e)(1).

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

D.1.6 Continuous Monitoring [40 CFR 63.427]

Pursuant to 40 CFR 63.427, the truck loading rack, identified as Loading Rack, has applicable compliance monitoring conditions as specified below:

(a) The Permittee install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in the following paragraph.

Where a flare is used, a heat-sensing device, such as an ultraviolet beam sensor or a thermocouple, shall be installed in proximity to the pilot light to indicate the presence of a flame.

(b) Pursuant to 40 CFR 63.11(b) (Control Device Requirements) the following apply to this air assisted flare:

(1) Permittee shall monitor the flare to assure that it is operated and maintained in conformance with their designs.

(2) The flare shall be operated at all times when the emissions may be vented to it.

(3) The flare shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(4) The flare shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(5) The flare shall be used only with the net heating value of the gas being combusted at 11.2 MJ/scm (300 Btu/scf) or greater.

(6) The air-assisted flare shall be designed and operated with an exit velocity less than the velocity Vmax. The maximum permitted velocity, Vmax for air-assisted flares shall be determined by the equation give in 40 CFR 63.11(b)(8).

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

D.1.7 Record Keeping Requirements [40 CFR 63.428]

(a) The Permittee shall keep records of the test results for each gasoline cargo tank loading at the gasoline distribution facility as follows:

(1) Annual certification testing performed under 40 CFR 63.425(e); and

(2) Continuous performance testing performed at any time at that gasoline distribution facility under 40 CFR 63.425 (f), (g), and (h).

(3) The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the gasoline distribution facility. The documentation for each test shall include, as a minimum, the following information:

(i) Name of test:
Annual Certification Test--Method 27 (40 CFR 63.425(e)(1)),
Annual Certification Test--Internal Vapor Valve (40 CFR 63.425(e)(2)),
Leak Detection Test (40 CFR 63.425(f)),
Nitrogen Pressure Decay Field Test (40 CFR 63.425(g)), or
Continuous Performance Pressure Decay Test (40 CFR 63.425(h)).

(ii) Cargo tank owner's name and address.

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

(vi) Witnessing inspector, if any: Name, signature, and affiliation.

(vii) Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.

(viii) Test results: Pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument and leak definition.

(b) The Permittee shall:

(1) Keep an up-to-date, readily accessible record of the continuous monitoring data required under 40 CFR 63.427(a). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

(2) Record and report simultaneously with the notification of compliance status required under 40 CFR 63.9(h):

(i) All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under 40 CFR 63.425(b); and

(ii) The following information when using a flare under provisions of 40 CFR 63.11(b) to comply with 40 CFR 63.422(b):

(A) Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and

(B) All visible emissions readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under 40 CFR 63.425(a).

(3) If a Permittee requests approval to use a vapor processing system or monitor an operating parameter other than those specified in 40 CFR 63.427(a), the Permittee shall submit a description of planned reporting and record keeping procedures. The IDEM, OAQ, and the USEPA Administrator will specify appropriate reporting and record keeping requirements as part of the review of the permit application.

(c) To document compliance with Condition D.1.6 the Permittee shall maintain records of the presence of pilot flame for the Loading Rack Flare.

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

D.1.8 Reporting Requirements [40 CFR 63.428]

(a) An initial notification required for existing affected source under 40 CFR 63.9(b)(2) was submitted on July 17, 1998.

(b) The Permittee shall include in a semiannual report to the IDEM, OAQ, and the USEPA Administrator the following information, as applicable:

(1) Each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the gasoline distribution facility;

(c) The Permittee shall submit an excess emissions report to the IDEM, OAQ, and the USEPA Administrator in accordance with 40 CFR 63.10(e)(3), whether or not a CMS is installed at the gasoline distribution facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable:

1. Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under 40 CFR 63.425(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

2. Each instance of a nonvapor-tight gasoline cargo tank loading at the gasoline distribution facility in which the Permittee failed to take steps to assure that such cargo tank would not be reloaded at the gasoline distribution facility before vapor tightness documentation for that cargo tank was obtained.

3. Each reloading of a nonvapor-tight gasoline cargo tank at the gasoline distribution facility before vapor tightness documentation for that cargo tank is obtained by the gasoline distribution facility in accordance with 40 CFR 63.422(c)(2).

(d) A reports, submitted to the IDEM, OAQ, shall be submitted to the addresses listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit.

SECTION D.2 **FACILITY OPERATION CONDITIONS**

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

(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; Under 40 CFR 63, Subpart UUU, process vents on the CCR are considered affected sources at a petroleum refinery.

(c) One (1) FCCU regenerator, identified as 500V-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; Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

(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: Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

 (1) One (1) Claus Unit Startup burner (SRU 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 (Claus Furnace 520-H-102), 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).

(nn) One (1) Vacuum heater, identified as 200-H6, with a maximum heat input rate of 5.49 mmBtu/hr, combusting refinery fuel gas and natural gas as a backup, installed in 2005 and exhausting to stack 126.

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

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

D.2.1 General Provisions Relating to 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), Sour Flare (124-4), and Vacuum heater (200-H6) 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), Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2), and Vacuum heater (200-H6):

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 Permittee 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 Permittee 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 500V-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), Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2), and Vacuum heater (200-H6) 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 demonstrate 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 demonstrate 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 demonstrate 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 demonstrate 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 chooses 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 H2S 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 H2S 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 H2S concentration is below 10 ppm, revert to using the 15 ppm Draeger tubes every 8 hours.
(5) If the H2S ever exceeds 80 ppm, install and certify an H2S CEM within 180 days and, in the meantime, follow this approved alternative monitoring method.
(6) Submit quarterly summary reports indicating all instances when the H2S concentration exceeded 10 ppm, the actual H2S 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), Gas Treatment System & Sulfur

Recovery System consisting of TGTU Incinerator Burner (124-2), and Vaccum heater (200-H6) 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 SO2 monitoring level equivalent to the H2S 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 SO2 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 Permittee 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 Permittee 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 H2S 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) continues 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 Permittee 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)]:

(d) The following storage vessels:

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
1	fixed roof cone tank	404,418	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	075;
2	fixed roof cone tank	404,502	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	076;
3	fixed roof cone tank	404,334	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	077;
4	fixed roof cone tank	118,272	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	018;
5	fixed roof cone tank	120,456	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	019;
6	fixed roof cone tank	120,456	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	020;
7	fixed roof cone tank	126,000	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	078;
8	fixed roof cone tank	126,000	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	079;
9	fixed roof cone tank	204,204	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1940	-	023;
10	fixed roof cone tank	121,590	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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 naptha,	1988	40 CFR Part 60, Subpart Kb	082;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
15	fixed roof cone tank	24,654	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1941	-	083;
17	fixed roof cone tank	997,584	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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	40 CFR Part 60, Subpart Kb	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	40 CFR 63, Subpart CC	120;
22B	fixed roof cone tank/insulated/heated cone tank	1,050,000	16,800	Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate,	2006	-	127;
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	40 CFR Part 60, Subpart Kb	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 naptha,	1946	-	085;
34	fixed roof cone tank	984,480	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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 Distillate,	1946	-	046;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
36	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,261,954	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of jet kerosene,	1946	-	047;
37	fixed roof cone tank	2,247,126	210,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1946	-	048;
38	fixed roof cone tank	2,248,386	210,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1948	-	049;;
39	fixed roof cone tank	2,250,234	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1948	-	050;
40	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,222,388	336,000	RVP 15 Gasoline.	1949	-	051;
41	fixed roof cone tank/internal floating roof tank,/mechanical 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 naptha,	1950	-	053;
43	fixed roof cone tank	2,254,098	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	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/mechanical primary seal	3,402,000	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of Distillate,	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	40 CFR Part 60, Subpart K	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;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
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 naptha,	1976	40 CFR Part 60, Subpart K	063;
53	fixed roof cone tank	16,926	168,000	Ethanol,	1985	40 CFR Part 60, Subpart Kb	086;
54	fixed roof cone tank	16,926	168,000	Ethanol,	1985	40 CFR Part 60, Subpart Kb	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 naptha,	1988	40 CFR Part 60, Subpart Kb	103;
160	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	40 CFR Part 60, Subpart Kb	104;
161	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	40 CFR Part 60, Subpart Kb	105;
162	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	40 CFR Part 60, Subpart Kb	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;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	NSPS and NESHAP applicability	Stack ID
165	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	40 CFR Part 60, Subpart Kb	109;
166	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	40 CFR Part 60, Subpart Kb	110;
167	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	40 CFR Part 60, Subpart Kb	111;
168	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	40 CFR Part 60, Subpart Kb	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	40 CFR Part 60, Subpart Kb	113;
125	fixed roof cone tank	157,000	6,000	hydrocarbon with vapor pressure of No.2 fuel oil or less	2005	-	015;
173	fixed roof cone tank/insulated/heated cone tank	1,050,000	16,800	Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate,	2006	-	128;
174	Fixed roof cone tank/insulated/heated cone tank	1,050,000	16,800	Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate,	2007	-	129
(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)							

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

D.3.1 General Provisions Relating to NSPS 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.

D.3.2 Volatile Organic Liquid Storage Vessels NSPS [326 IAC 12] [40 CFR 60, Subpart K]

The tanks identified as 47 and 52 are subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.110, Subpart K) "Standards of Performance for Storage Vessels for Petroleum Liquids," because they have a storage capacity greater than 40,000 gallons and were constructed after June 11, 1973 and prior to May 19, 1978.

D.3.3 Volatile Organic Liquid Storage Vessels NSPS [326 IAC 12] [40 CFR Part 60, Subpart Kb]

(a) The provisions of 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (including petroleum liquid tanks) for which construction, reconstruction, or modification commenced after July 23, 1984, which are incorporated by reference as 326 IAC 12, apply to tank Nos. 18 and 24. The Permittee shall comply with the requirements of this rule upon startup of the gasoline distribution facility.

(b) Pursuant to 40 CFR Part 60.110b, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels), tank Nos. 12, 53, 54, 159, 160, 161, 162, 165, 166, 167, 168 and 169, each with storage capacity of greater than 40 cubic meters and less than 75 cubic meters, are only subject to 40 CFR Part 60.116b, paragraphs (a), (b), and (d) which require record keeping.

D.3.4 Standards for Volatile Organic Compounds Emissions from Storage Vessels [40 CFR 60.112] [Subpart K]

Pursuant to 326 IAC 12 and 40 CFR 60.112, the Permittee of the tanks identified as 47 and 52 shall equip each tank with one (1) of the following:

(a) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the tank shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(b) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the tank shall be equipped with a vapor recovery system or its equivalent.

D.3.5 Standards for Volatile Organic Compounds Emissions from Storage Vessels [40 CFR 60.112b] [Subpart Kb]

Pursuant to 326 IAC 12 and 40 CFR 60.112b, the Permittee has equipped and shall continue to equip tank Nos. 18 and 24 with a fixed roof in combination with an internal floating roof meeting the following specifications:

(a) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a tank that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the tank is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(b) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the tank and the edge of the internal floating roof:

(1) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the tank and the floating roof continuously around the circumference of the tank.

(2) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the tank and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(3) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the tank by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(c) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(d) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(e) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(f) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(g) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(h) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(i) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

D.3.6 Storage Vessel Provisions [326 IAC 20-10-1] [40 CFR Part 63, Subpart CC]

All storage vessels that are affected facilities under 40 CFR Part 63, Subpart CC, shall comply with the provisions of 40 CFR 63.646 (listed under condition D.4.6).

D.3.7 Volatile Organic Compounds (VOC) [326 IAC 8-4-3]

Pursuant to 326 IAC 8-4-3, Tank Nos. 18 and 24 are subject to the following:

(a) The facility must be equipped with an internal floating roof equipped with a closure seal, or seals, to close the space between the roof edge and tank wall unless the source has been equipped with equally effective alternative control which has been approved.

(b) The facility is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials.

(c) All openings, except stub drains, are equipped with covers, lids, or seals such that:

(1) the cover, lid, or seal is in the closed position at all times except when in actual use;

(2) automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports;

(3) rim vents, if provided are set to open when the roof is being floated off the roof leg supports or at the manufacturer’s recommended setting.

D.3.8 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 storage tanks identified as Nos. 47 and 24 and any control devices.

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

D.3.9 Performance Testing [40 CFR 60.113b]

The Permittee of tanks (18 and 24) as specified in 40 CFR 60.112b(a), shall meet the following requirements. The applicable paragraph for a particular tank depends on the control equipment installed to meet the requirements of 40 CFR 60.112b.

After installing the control equipment required to meet 40 CFR 60.112b(a)(1) (permanently affixed roof and internal floating roof), each Permittee shall:

(a) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the tank with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the Permittee shall repair the items before filling the tank.

(b) With a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the tank, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the Permittee shall repair the items or empty and remove the tank from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in 40 CFR 60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(c) For vessels equipped with a double-seal system as specified in 40 CFR 60.112b(a)(1)(ii)(B):

    (1) Visually inspect the vessel as specified in paragraph (d) of this section at least every 5 years; or
    (2) Visually inspect the vessel as specified in paragraph (b) of this section.

(d) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the tank is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, 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 the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the Permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the tank with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (b) and (c)(2) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (c)(1) of this section.

(e) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each tank for which an inspection is required by paragraphs (a) and (d) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (d) of this section is not planned and the Permittee could not have known about the inspection 30 days in advance or refilling the tank, the Permittee shall notify the Administrator at least 7 days prior to the refilling of the tank. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

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

D.3.10 Monitoring of Storage Vessels [40 CFR 60.113] [40 CFR 60.116b]

Pursuant to 40 CFR 60.113, the Permittee shall comply with the applicable compliance monitoring requirements specified below for tanks identified as 47 and 52:

(a) Except as provided in 40 CFR 60.113 paragraph (d), the Permittee subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

Pursuant to 40 CFR 60.116b, The Permittee shall comply with the applicable compliance monitoring requirements specified below for tanks identified as 18 and 24:

(a) The Permittee shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The Permittee of each tank as specified in 40 CFR 60.110b(a) shall keep readily accessible records showing the dimension of the tank and an analysis showing the capacity of the tank.

(c) The Permittee of each tank shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) The Permittee of each tank either with a design capacity greater than or equal to 151 m3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m3 but less than 151 m3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

    (1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference--see 40 CFR 60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:
(i) May be obtained from standard reference texts, or
(ii) Determined by ASTM Method D2879-83 (incorporated by reference--see 40 CFR 60.17); or
(iii) Measured by an appropriate method approved by the Administrator; or
(iv) Calculated by an appropriate method approved by the Administrator.

The Permittee shall comply with the monitoring requirements in 40 CFR 60.116b.

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

D.3.11 Record Keeping and Reporting [40 CFR 60.115b]

The Permittee of tank Nos. 18 and 24 as specified in 40 CFR 60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of 40 CFR 60.112b. The Permittee shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with 40 CFR 60.112b(a)(1) (fixed roof and internal floating roof), the Permittee shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR 60.112b(a)(1) and 40 CFR 60.113b(a)(1). This report shall be an attachment to the notification required by 40 CFR 60.7(a)(3).

(2) Keep a record of each inspection performed as required by 40 CFR 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the tank on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in 40 CFR 60.113b(a)(2) are detected during the annual visual inspection required by 40 CFR 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the tank, the nature of the defects, and the date the tank was emptied or the nature of and date the repair was made.

(4) After each inspection required by 40 CFR 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 40 CFR 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the

tank and the reason it did not meet the specifications of 40 CFR 61.112b(a)(1) or 40 CFR 60.113b(a)(3) and list each repair made.

(b) To document compliance with Condition D.3.10, the Permittee shall maintain records of all the required parameters listed in Condition D.3.10.

Pursuant to 40 CFR Part 60.110b, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels), storage tanks identified as Nos. 53, 54, 159, 160, 161, 162, 165, 166, 167, 168 and 169, with a storage capacity of greater than 40 cubic meters and less than 75 cubic meters, are subject to following recordkeeping requirements.

(a) The Permittee shall maintain permanent records at the source in accordance with (1) through (2) below:

(1) the dimension of the storage vessel; and
(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)]:

(t) Two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071; Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected sources at a petroleum refinery.

(u) One (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;

(v) Pipeline Valves - Gas, identified as 090; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(w) Pipeline Valves - Light Liquid, identified as 091; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(x) Pipeline Valves - Heavy Liquid, identified as 092; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(y) Pipeline Valves - Hydrogen, identified as 093; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(z) Open Ended Valves, identified as 094; Under 40 CFR 60, Subpart GGG, open-ended valves are considered affected sources at a petroleum refinery.

(aa) Flanges, identified as 095; Under 40 CFR 60, Subpart GGG, the flanges are affected considered sources at a petroleum refinery.

(bb) Pump Seals Light Liquid, identified as 096; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(cc) Pump Seals Heavy Liquid, identified as 097; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(dd) Compressor Seals - Gas, identified as 098; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ee) Compressor Seals - Heavy Liquid, identified as 099; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ff) Drains, identified as 100.

(gg) Vessel Relief Valves, identified as 101; Under 40 CFR 60, Subpart GGG, pressure relief devices are considered affected sources at a petroleum refinery.

(hh) Cooling Towers, identified as 119.

(ii) Process units made up of vessels, piping, exchangers, identified as PENEX. Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery.

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of: Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery. Under 40 CFR 63, Subpart CC, equipment leaks from storage vessels and equipment leaks associated with a bulk gasoline terminal are considered affected sources.
(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.
(14) cooling Towers, identified as 119.

(qq) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja (currently under stay) the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGGa, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

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

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

D.4.1 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^{o} 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 judgment 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

(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 [40 CFR 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 [40 CFR 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 [40 CFR 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 Closed Vent Systems and Control Devices [40 CFR 60.692-6] [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 [40 CFR 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 [40 CFR 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 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 [40 CFR 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 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 co (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 28oC (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 demonstrate 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 [40 CFR 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)]:

(e) One (1) Main Refinery Flare, identified as 700-V101 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 replaced in 2006 and to stack 118;

Under 40 CFR Part 60, Subpart Ja (currently under stay) the Main Refinery Flare is considered an affected facility.

(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 400-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 900-H1 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 200-H4 with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950, approved to be modified in 2007, and exhausting to stack 5.

(k) One (1) Old Platformer heater, identified as Naphtha Splitter Reboiler 900-H2, 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 100-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 200-H1 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 300-H4 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 200-H3 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.

(b) One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as 500-H101 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.

(qq) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja (currently under stay) the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGGa, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

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

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

D.5.1 Particulate 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 Particulate Matter (PM) [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Matter Emissions Limitations), particulate emissions from the 5.985 MMBtu/hr LSG Charge Reactor Heater shall not exceed 0.1 pounds per MMBtu heat input.

D.5.3 Sulfur Dioxide (SO2) [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, 200-H4, 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.5.4 No. 6 Fuel Usage [326 IAC 2-2]

The input of No. 6 fuel oil to the four(4) boilers B1, B2, B3, and B4, 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.5.5 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.5.6 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.5.7 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition D.5.3 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.5.8 Visible Emissions Notations

(a) Visible emission notations of the boiler stacks (B1, B2 and B3) exhaust shall be performed once per day during normal daylight operations 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) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

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

D.5.9 Record Keeping Requirements

(a) To document compliance with Conditions D.5.3, 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.5.5, 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.5.10 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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region V
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).

SECTION D.6 FACILITY OPERATION CONDITIONS

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

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]

(d) Welding/Cutting of metal for vessel, pipeline and equipment maintenance. [326 IAC 6-3]

(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)]

Process Weight Activities

D.6.1 Particulate Matter Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) pounds per hour [326 IAC 6-3-2(c)]

Pursuant to 326 IAC 6-3-2(c), the allowable particulate matter emissions rate from any process not already regulated by 326 IAC 6-1 or any New Source Performance Standard, and which has a maximum process weight rate less than 100 pounds per hour shall not exceed 0.551 pounds per hour. This includes the following operations:

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

SECTION E.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-8-4(10)]:

(oo) One (1) no. 4 boiler, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131.

Under the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Dc), the boiler B4, is considered a new source.

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

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

E.1.1 Sulfur Dioxide (SO2) [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 boiler B4, 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.

E.1.2 PSD Minor Limit [326 IAC 2-2]

The input of No. 6 fuel oil to Boiler B4 shall be limited to less than 730,000 gallons (with maximum fuel oil sulfur content of 0.5% based on the Subpart Dc) per twelve (12) consecutive month period, with compliance determined at the end of each month. This fuel oil usage limit for boiler B4 is part of the total fuel oil usage limit of 3,214.92 thousand gallons per year for all four (4) boilers (B1, B2, B3 and B4) as specified in Condition D.5.3.

E.1.3 General Provisions Relating to NSPS [326 IAC 12-1] [40 CFR 60, Subpart A]

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

E.1.4 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Dc]

Pursuant to 40 CFR Part 60, Subpart Dc, the Permittee shall comply with the provisions of the National Source Performance Standards for Small Industrial-Commercial- Institutional Steam Generating Units, as specified as follows.

§ 60.40c Applicability and delegation of authority.

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

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

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

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

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

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

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

§ 60.41c Definitions.

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

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

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR--see Sec. 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

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

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

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

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

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

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference -- see § 60.17).

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

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

Emerging technology means any SO2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

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

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

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

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

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

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

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

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

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

Potential sulfur dioxide emission rate means the theoretical SO2 emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

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

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference -- see § 60.17).

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

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

Wet flue gas desulfurization technology means an SO2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO2.

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

§ 60.42c Standard for sulfur dioxide.

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

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

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

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

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

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(i) The SO2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

§ 60.43c Standard for particulate matter.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

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

(e)(1) On or after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2) and (e)(3) of this section. Affected facilities subject to this paragraph, are also subject to the requirements of paragraphs (c) and (d) of this section.
(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:
(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, and

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

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

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

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

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

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

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

$E_{ho}{}^{o} = [E_{ho}-E_{w}(1-X_{k})]/X_{k}$

where:

$E_{ho}{}^{o}$ is the adjusted E_{ho}, ng/J (lb/million Btu).
E_{ho} is the hourly sulfur dioxide emission rate, ng/J (lb/million Btu).
E_{w} is the SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 9, ng/J (lb/million Btu). The value E_{w} for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure Ew if the owner or operator elects to assume $E_{w} = 0$.
X_{k} is the fraction of total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) [where percent reduction is not required] does not have to measure the parameters E_{w} or X_{k} if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:
(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

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

$\%R_{g}{}^{o}=100\ [1.0- E_{ao}{}^{o}/E_{ai}{}^{o})]$

where:
$\%Rg^{o}$ is the adjusted $\%R_{g}$, in percent
$E_{ao}{}^{o}$ is the adjusted E_{ao}, ng/J (lb/million Btu)
$E_{ai}{}^{o}$ is the adjusted average SO_2 inlet rate, ng/J (lb/million Btu)

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

$E_{hi}{}^{o} = [E_{hi}-E_{w}(1-X_{k})]/X_{k}$

where:

$E_{hi}{}^{o}$ is the adjusted hourly E_{hi}, ng/J (lb/million Btu).
E_{hi} is the hourly sulfur dioxide inlet rate, ng/J (lb/million Btu).
E_{w} is the sulfur dioxide concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The value E_{w} for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_{w} if the owner or operator elects to assume $E_{w} = 0$.
X_{k} is the fraction of total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

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

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

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

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

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

(1) Method 1 shall be used to select the sampling site and the number of traverse sampling points.
(2) Method 3 shall be used for gas analysis when applying Method 5, Method 5B, or Method 17.
(3) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of PM as follows:

(i) Method 5 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B may be used in Method 17 only if Method 17 is used in conjunction with a wet scrubber system. Method 17 shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or Method 5B, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen or carbon dioxide measurement shall be obtained simultaneously with each run of Method 5, Method 5B, or Method 17 by traversing the duct at the same sampling location.

(7) For each run using Method 5, Method 5B, or Method 17, the emission rates expressed in ng/J (lb/million Btu) heat input shall be determined using:

(i) The oxygen or carbon dioxide measurements and PM measurements obtained under this section,

(ii) The dry basis F-factor, and

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

(8) Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(d) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall install, calibrate, maintain, and operate a continuous emission monitoring system and shall comply with the requirements specified in paragraphs (d)(1) through (d)(13) of this section.

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

(2) Notify the Administrator 1 month before stopping use of the system.

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

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

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

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

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

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

(ii) [Reserved]

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

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

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraph (d)(7)(i) of this section.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA reference Method 3, 3A, or 3B, as applicable shall be used.

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

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

§ 60.46c Emission monitoring for sulfur dioxide

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation and include at least 2 data points representing two 15-minute periods. Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

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

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new

shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 (appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3 or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, oil, gas, or wood that is subject to the opacity standards under Sec. 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system, except as specified in paragraphs (c) and (d) of this section.

(b) All COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (appendix B). The span value of the opacity COMS shall be between 60 and 80 percent.

(d) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in Sec. 60.45c(d). The continuous monitoring systems specified in paragraph Sec. 60.45c(d) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

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

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

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

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of

the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier; and

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.

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

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

E.1.5 One Time Deadlines Relating to Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS [40 CFR 60, Subpart Dc]:

The Permittee shall comply with the following notification requirements by the dates listed:

Requirement	Rule Cite	Affected Facility	Deadline
Submit notification of the date of construction or reconstruction, anticipated startup, and actual startup.	60.48c	B4	As provided by § 60.7 of this part.

Compliance Determination Requirements

E.1.6 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition E.1.1 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)]

E.1.7 Visible Emissions Notations

(a) Visible emission notations of the boiler stack (B4) exhaust shall be performed once per day during normal daylight operations 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) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

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

E.1.8 Record Keeping Requirements

(a) To document compliance with Conditions E.1.1 and E.1.2, 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 E.1.7, the Permittee shall maintain records of visible emission notations of the boiler stack (B4) once per day.

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

E.1.9 Reporting Requirements

A quarterly summary of the information to document compliance with Condition E.1.2 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION E.2 **FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-8-4(10)]:

(pp) One (1) fixed roof, cone tank, internal floating roof, identified as Tank No. 175, with a capacity of 2,310,000 gallons and a maximum withdrawal rate of 210,000 gallons per hour of petroleum with vapor pressure of 13 RVP gasoline or less and exhausting to stack 130 (start construction in second quarter of 2007 and to be completed by February 2008);

Under the Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 CFR Part 60, Subpart Kb], the Tank No. 175, is considered a new source.

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

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

E.2.1 General Provisions Relating to NSPS [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 by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart Kb.

E.2.2 Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 CFR Part 60, Subpart Kb]

Pursuant to 40 CFR Part 60, Subpart Kb, the Permittee shall comply with the provisions of the National Source Performance Standards for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, as specified as follows.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151m3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, rail-cars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) Alternative means of compliance -- (1) Option to comply with part 65. Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§ 60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of § 60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m3 but less than 151 m3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) Part 60, subpart A. Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) Internal floating roof report. If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) External floating roof report. If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods de-scribed in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see § 60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM Method D2879–83, 96, or 97 (incorporated by reference— see § 60.17);

(4) Any other method approved by the Administrator.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see § 60.17).

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.
[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m3 but less than 151 m3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer’s recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of § 60.112b.

(a) After installing the control equipment required to meet § 60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in § 60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, 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 the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112b, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in § 60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of § 60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Keep a record of each inspection performed as required by § 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.
(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of § 61.112b(a)(1) or § 60.113b(a)(3) and list each repair made.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in § 60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m 3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m 3 but less than 151 m 3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m 3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m 3 but less than 151 m 3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see § 60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or
(ii) Determined by ASTM Method D2879–83, 96, or 97 (incorporated by reference— see § 60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM Method D2879–83, 96, or 97 (incorporated by reference—see § 60.17); or

(ii) ASTM Method D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§ 60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

SECTION E.3 **FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-8-4(10)]:

(oo) One (1) no. 4 boiler, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131.

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

E.3.1 General Provisions Relating to NSPS [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 by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart J.

E.3.2 Standards of Performance for Petroleum Refineries [40 CFR Part 60, Subpart J]

Pursuant to 40 CFR Part 60, Subpart J, the Permittee shall comply with the provisions of the National Source Performance Standards for Petroleum Refineries, as specified as follows.

§ 60.100 Applicability, designation of affected facility, and reconstruction.

(a) 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.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this sub-part except as provided under paragraphs (c) and (d) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction or modification on or before January 17, 1984, is exempted from § 60.104(b).

(d) 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.

(e) For purposes of this subpart, under § 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 an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to under-take and complete, within a reasonable time, a continuous program of component replacement.

§ 60.101 Definitions.

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

(a) *Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) *Process gas* means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

(e) *Process upset gas* means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) *Refinery process unit* means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) *Fuel gas combustion device* means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) *Coke burn-off* means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

(i) *Claus sulfur recovery plant* means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) *Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) *Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) *Reduced sulfur compounds* means hydrogen sulfide (H2S), carbonyl sulfide (COS) and carbon disulfide (CS2).

(m) *Fluid catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously re-generated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

(n) *Fluid catalytic cracking unit catalyst regenerator* means one or more regenerators (multiple regenerators) which comprise that portion of the fluid catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

(o) *Fresh feed* means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

(p) *Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

(q) *Valid day* means a 24-hour period in which at least 18 valid hours of data are obtained. A ‘‘valid hour’’ is one in which at least 2 valid data points are obtained.

§ 60.104 Standards for sulfur oxides.

Each owner or operator 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.

(a) No owner or operator subject to the provisions of this subpart shall:
(1) 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.

§ 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:
(3) For fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO2 emissions into the atmosphere (except where an H2S monitor is installed under paragraph (a)(4) of this section). 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 SO2 monitoring level equivalent to the H2S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).
(iii) The performance evaluations for this SO2 monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 2A 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.

(4) In place of the SO2 monitor in paragraph (a)(3) of this section, 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 § 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.
(b) [Reserved]

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

NOTE: All averages, except for opacity, shall be determined as the arithmetic aver-age of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be deter-mined as the arithmetic average of three contiguous 1-hour averages.

(1) *Opacit*y. All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under § 60.105(a)(1) exceeds 30 percent.

(3) *Sulfur dioxide from fuel gas combustio*n.
(i) All rolling 3-hour periods during which the average concentration of SO2 as measured by the SO2 continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H2S as measured by the H2S continuous monitoring system under § 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

§ 60.106 Test methods and procedures.

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

(e)(1) The owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11, 15, 15A, or 16 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.
(i) For Method 11, 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.
(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.
(iii) For Method 15A, a 1-hour sample shall constitute a run.
(2) Where emissions are monitored by § 60.105(a)(3), compliance with § 60.105(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. A 1-hour sample shall constitute a run. Method 6 samples shall be taken at a rate of approximately 2 liters/min. The ppm correction factor (Method 6) and the sampling location in paragraph (f)(1) of this section apply. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C.

§ 60.107 Reporting and recordkeeping requirements.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability 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 owner or operator of an affected facility shall submit the reports required under this subpart to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(f) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

§ 60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in § 60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under § 60.104(b). Performance tests conducted for the purpose of determining compliance under § 60.104(b) shall be conducted according to the applicable procedures specified under § 60.106.

§ 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.
(b) Authorities which shall not be delegated to States:
(1) Section 60.105(a)(13)(iii),
(2) Section 60.106(i)(12).

SECTION E.4 FACILITY OPERATION CONDITIONS

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

(qq) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja (currently under stay) the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGGa, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

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

E.4.1 General Provisions Relating to NESHAP Subpart FF [40 CFR Part 61, Subpart A]

Pursuant to 40 CFR 61.340, the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1-1, except as otherwise specified in 40 CFR Part 61, Subpart FF.

E.4.2 Benzene Waste Operations NESHAP [40 CFR Part 61, Subpart FF]

The Permittee which engages benzene waste operations shall comply with the following provisions of 40 CFR Part 61, Subpart FF (included as Attachment A of this permit).

(1) 40 CFR 61.340
(2) 40 CFR 61.341
(3) 40 CFR 61.342(a)
(4) 40 CFR 61.355
(5) 40 CFR 61.356(a)(b)(1)
(6) 40 CFR 61.357(a)(c)

SECTION E.5 FACILITY OPERATION CONDITIONS

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

(qq) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja (currently under stay) the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGGa, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

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

E.5.1 General Provisions Relating to NSPS Subpart GGGa [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12, except as otherwise specified in 40 CFR Part 60, Subpart GGGa.

E.5.2 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 NSPS [40 CFR Part 60, Subpart GGGa]

The Permittee which engages in petroleum refineries for which construction, reconstruction, or modification commenced after November 7, 2006 shall comply with the following provisions of 40 CFR Part 60, Subpart GGGa, (included as Attachment B of this permit).

(1) 40 CFR 60.590a

(2) 40 CFR 60.591a

(3) 40 CFR 60.592a

SECTION E.6 FACILITY OPERATION CONDITIONS

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

(e) One (1) Main Refinery Flare, identified as 700-V101 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 replaced in 2006 and exhausting to stack 118;

Under 40 CFR Part 60, Subpart Ja (currently under stay) the Main Refinery Flare is considered an affected facility.

(qq) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja (currently under stay) the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGGa, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

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

E.6.1 General Provisions Relating to NSPS Subpart Ja [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12, except as otherwise specified in 40 CFR Part 60, Subpart Ja.

E.6.2 Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 NSPS [40 CFR Part 60, Subpart Ja (Currently Under Stay Until September 26, 2008)]

The Permittee which engages in petroleum refineries for which construction, reconstruction, or modification commenced after May 14, 2007 shall comply with the following provisions of 40 CFR Part 60, Subpart Ja, (included as Attachment C of this permit).

(1) 40 CFR 60.100a

(2) 40 CFR 60.101a

(3) 40 CFR 60.102a(g)

(4) 40 CFR 60.103a(a)(b)

(5) 40 CFR 60.104a(j)(4)(iv)

(6) 40 CFR 60.107a(a)(2)(d)(e)

(7) 40 CFR 60.108a

(8) If the rule language should change after the stay the changes shall also apply.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

PART 70 OPERATING PERMIT
CERTIFICATION

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

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

COMPLIANCE AND ENFORCEMENT BRANCH
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: 317-233-0178
Fax: 317-233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: 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

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

☐ This is an emergency as defined in 326 IAC 2-7-1(12)
- X The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- X The Permittee must submit notice in writing or by facsimile within two (**2**) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

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

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

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

Page 2 of 2

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

Form Completed by:_______________________________

Title / Position:_________________________________

Date:____

Phone: _______________________________________

A certification is not required for this report.

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

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, B3, and B4
Parameter: No. 6 Fuel Oil Usage
Limit: The input of No. 6 fuel oil to the four boilers B1, B2, B3, and B4 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
COMPLIANCE AND ENFORCEMENT BRANCH

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: B4
Parameter: No. 6 Fuel Oil Usage
Limit: The input of No. 6 fuel oil to the boiler B4 based on a maximum fuel oil sulfur content of 0.5 percent shall be limited, to 730,000 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
COMPLIANCE AND ENFORCEMENT BRANCH

PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING 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

Months: ___________ to ___________ Year: _____________

Page 1 of 2

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

Page 2 of 2

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed by:________________________________

Title / Position:__________________________________

Date:____

Phone: ____

Attach a signed certification to complete this report.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Administrative Amendment

Source Description and Location

Source Name:	Countrymark Cooperative, LLP
Source Location:	1200 Refinery Road, Mount Vernon, Indiana 47620
County:	Posey
SIC Code:	2911
Operation Permit No.:	129-7882-00003
Operation Permit Issuance Date:	July 21, 2003
Administrative Amendment No.:	129-28028-00003
Permit Reviewer:	Mehul Sura

Source Definition

This stationary petroleum refinery source 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 are under common control of the same entity, they are considered one (1) source, effective from the date of issuance of this Part 70 permit.

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

Existing Approvals

The source was issued Part 70 Operating Permit No. T129-7882-00003 on July 21, 2003. The source has since received the following approvals:

(a) Significant Permit Modification No.: 129-17940-00003, issued on November 24, 2003

(b) Significant Permit Modification No.: 129-20112-00003, issued on March 21, 2005

(c) Administrative Amendment No.: 129-20343-00003, issued on March 30, 2005

(d) Significant Permit Modification No.: 129-21251-00003, issued on August 15, 2005

(e) Significant Permit Modification No. 129-23090-00003, issued on January 30, 2007

(f) Significant Permit Modification No. 129-24761-00003, issued on December 17, 2007

(g) Significant Permit Modification No. 129-24761-00003, issued on December 17, 2007

(h) Significant Permit Modification No. 129-26980-00003, issued on January 27, 2009

County Attainment Status

The source is located in Posey County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective April 5, 2005, for PM2.5.	

(a) Ozone Standards

(1) On October 25, 2006, the Indiana Air Pollution Control Board finalized a rule revision to 326 IAC 1-4-1 revoking the one-hour ozone standard in Indiana.

(2) 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 and NOx emissions are considered when evaluating the rule applicability relating to ozone. Posey County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) PM2.5
Posey County has been classified as attainment for PM2.5. On May 8, 2008 U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for PM2.5 emissions, and the effective date of these rules was July 15, 2008. Indiana has three years from the publication of these rules to revise its PSD rules, 326 IAC 2-2, to include those requirements. The May 8, 2008 rule revisions require IDEM to regulate PM10 emissions as a surrogate for PM2.5 emissions until 326 IAC 2-2 is revised.

(c) Other Criteria Pollutants
Posey County has been classified as attainment or unclassifiable in Indiana for SO2, NOx, PM10, and CO. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(d) Since this source is classified as a petroleum refinery, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1).

(e) Fugitive Emissions
Since this type of operation is not one of the twenty-eight (28) listed source categories under 326 IAC 2-2 or 326 IAC 2-3, fugitive emissions are not counted toward the determination of PSD and Emission Offset applicability.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Countrymark Cooperative, LLP on May 29, 2009, requesting changes to its existing permitted emission units in order to lower Benzene levels in gasoline below 0.62% by volume to meet the requirements of the Mobile Source Air Toxics (MSAT) phase II (72 FR 8428; 2/26/2007). Countrymark Cooperative, LLP will achieve the Benzene reduction in gasoline through "1.14 % by volume reduction of Benzene precursors" in the existing CCR Platformer Unit.

The following changes will be made to its existing permitted emission units:

(a) The burners of old platformer heater (P-H1), with a maximum heat input capacity of 29 MMBtu/hr, will be replaced with six burners (each with 4.6 MMBtu/hr heat input capacity), with a total heat input capacity of 27.6 MMBtu/hr.

(b) The changes shown below will be made to a naphtha splitter. The naphtha splitter is not listed in the permit since the only emissions associated with this equipment is fugitive VOC emissions due to the leaks from its components (pipes, valves, etc.). These components are listed under common a group (Condition A.3(mm)) in the permit.

(1) Replace 42 of the 47 trays in the column with high efficiency 'SUPERFRAC' trays.

(2) Add one overhead condenser parallel to the current condenser.

(3) Increase reflux pump and bottom pump capacities by replacing impellers and changing motors.

(4) Install a second reflux pump.

Countrymark Cooperative, LLP has also requested following identification number changes for the existing emission units:

Emission Unit Description	Current Identification Number In The Permit	New Identification Number
One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater	H-101	500-H101
One (1) FCCU regenerator	V-5	500V-5
Main Refinery Flare	RCD-1	700-V101
Crude heater	C-11	200-H2
Unifiner heater	H-H5	400-H5
Naphtha splitter heater	H-H3	900-H1
Vacuum heater	V-IV	200-H4
Old Platformer heater	P-H1	Naphtha Splitter Reboiler 900-H2
Alkylation unit heater	A-H1	100-H1
Auxiliary crude heater	C-I	200-H1
Platformer stabilizer reboiler	P-H2	300-H4
Vacuum heater husky	VIII	200-H3
Claus Unit Startup burner	520-H-101	SRU Burner 520-H-101
Tail Gas Treating Unit (TGTU) Incinerator burner	520-H-101	Claus Furnace 520-H-102

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

There is no emission increase in any of the pollutants due to the following reason:

The Benzene precursor, separated during the process, is converted into the isomers. These isomer are eventually blended with the gasoline that is supplied to the customers.

Permit Level Determination – Part 70

This modification involves revising the descriptive information and these revisions do not trigger new applicable requirement or violate a permit term. Therefore, this modification will be made through an administrative amendment pursuant to 326 IAC 2-7-11(a)(7).

Permit Level Determination – PSD

This administrative amendment does not cause any emissions increase of regulated NSR (New Source Review) pollutants. Therefore, the requirements of 326 IAC 2-2 (PSD) are not applicable.

Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this change:

New Source Performance Standards (NSPS):

No new emission unit is being added due to this change.

The P-H1 is being modified by replacing existing 29 MMBtu/hr (total) heat capacity burners with 27.6 MMBtu/hr (total) heat capacity burners. This change is not considered as a modification under NSPS because emissions are not increased due to this change. Based on the information submitted by the Countrymark Cooperative, LLP related to cost involved in this change, shows that the fixed capital cost of the new components does not exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Therefore, this change is not considered as a reconstruction. Since changes to the P-H1 are not considered as modification or reconstruction, no NSPS (NSPS)(326 IAC 12 and 40 CFR Part 60) is included in the permit due to this change.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

There are no NESHAP (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included in the permit due to this change.

State Rule Applicability Determination

There are no new state rules that are applicable due to this modification.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source’s failure to take the appropriate corrective actions within a specific time period.

There are no new compliance monitoring requirements applicable to this modification.

Changes to the permit

The changes listed below have been made to Part 70 Operating Permit Renewal No. 039-17988-00086. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

(a) Condition A.2 has been revised for clarity purpose.

(b) Identification number changes for the existing emission units have been changed as described in Description of Proposed Modification section of this TSD.

(c) IDEM, OAQ is revising Section B - Emergency Provisions to allow the Permittee to reference a previously reported emergency under paragraph (b)(5) in the Quarterly Deviation and Compliance Monitoring Report.

(d) Several of IDEM's Branches and sections have been renamed. Therefore, IDEM has updated the addresses listed in the permit. References to Permit Administration and Development Section and the Permits Branch have been changed to Permit Administration and Support Section. References to Asbestos Section, Compliance Data Section, Air Compliance Section, and Compliance Branch have been changed to Compliance and Enforcement Branch.

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

. . .

Separate Part 70 permits ~~will be~~**have been** 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) . . .

(b) One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as ~~H-101~~**500-H101** 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~~**500V-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; Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

(d) . . .

(e) One (1) Main Refinery Flare, identified as ~~RCD-1~~**700-V101** 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 replaced in 2006 and exhausting to stack 118;
Under 40 CFR Part 60, Subpart Ja (currently under stay) the Main Refinery Flare is considered an affected facility.

(f) . . .

(g) One (1) Unifiner heater, identified as ~~H-H5~~**400-H5** with a maximum heat input rate of 20 mmBtu/hr, combusting refinery fuel gas, installed in 1959 and exhausting to stack 2;

(h) . . .

(i) One (1) Naphtha splitter heater, identified as ~~H-H3~~**900-H1** 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~~**200-H4** with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950, approved to be modified in 2007, and exhausting to stack 5;

(k) One (1) Old Platformer heater, identified as ~~P-H1~~**Naphtha Splitter Reboiler 900-H2,** with a maximum heat input rate of ~~29~~ **27** mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 6;

(l) One (1) Alkylation unit heater, identified as ~~A-H1~~**100-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~~**200-H1** 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~~**300-H4** with a maximum heat input rate of 5.92 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 12;

. . .

(r) One (1) Vacuum heater husky, identified as ~~VIII~~**200-H3** 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;

. . .

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following: Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

(1) One (1) Claus Unit Startup burner (~~520-H-101~~**SRU 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~~**Clause Furnace 520-H-102**), 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.

. . .

(mm) . . .

. . .

B.11 Emergency Provisions [326 IAC 2-7-16]

. . .

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report. **Any emergencies that have been previously reported pursuant to paragraph (b)(5) of this condition and certified by a "responsible official" need only referenced by the date of the original report.**

. . .

SECTION D.2 FACILITY OPERATION CONDITIONS

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

(s) . . .

(c) One (1) FCCU regenerator, identified as ~~V-5~~**500V-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; Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

. . .

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following: Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

(1) One (1) Claus Unit Startup burner (~~520-H-101~~**SRU 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~~**Clause Furnacer 520-H-102**), 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) . . .

(4) . . .

. . .

. . .

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~~**500V-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.

. . .

SECTION D.5 FACILITY OPERATION CONDITIONS

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

(e) One (1) Main Refinery Flare, identified as ~~RCD-1~~**700-V101** 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 replaced in 2006 and to stack 118;

Under 40 CFR Part 60, Subpart Ja (currently under stay) the Main Refinery Flare is considered an affected facility.

(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~~**400-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~~**900-H1** 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~~**200-H4** with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950, approved to be modified in 2007, and exhausting to stack 5.

(k) One (1) Old Platformer heater, identified as ~~P-H1~~**Naphtha Splitter Reboiler 900-H2,** with a maximum heat input rate of ~~29~~ **27** mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 6.

(l) One (1) Alkylation unit heater, identified as ~~A-H1~~**100-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~~**200-H1** 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~~**300-H4** with a maximum heat input rate of 5.92 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 12.

. . .

(r) One (1) Vacuum heater husky, identified as ~~VIII~~**200-H3** 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.

(b) One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as ~~H-101~~**500-H101** 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.

. . .

. . .

D.5.3 Sulfur Dioxide (SO2) [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~~**200-H4**, 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.

. . .

SECTION E.6 FACILITY OPERATION CONDITIONS

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

(e) One (1) Main Refinery Flare, identified as ~~RCD-1~~**700-V101** 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 replaced in 2006 and exhausting to stack 118;

Under 40 CFR Part 60, Subpart Ja (currently under stay) the Main Refinery Flare is considered an affected facility.

. . .

. . .

Conclusion and Recommendation

This administrative amendment shall be subject to the conditions of the attached Part 70 Administrative Amendment No. 129-28028-00003. The staff recommend to the Commissioner that this Part 70 Administrative Amendment be approved.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

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

TO: Jim Pankey
Countrymark Cooperative, LLP
1200 Refinery Rd
Mount Vernon, IN 47620

DATE: June 26, 2009

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

SUBJECT: Final Decision
Administrative Amendment
129-28028-00003

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

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

A copy of the final decision and supporting materials has also been sent via standard mail to:
Matthew Smorch (Manager)
Pat Sorenson (ERM)
OAQ Permits Branch Interested Parties List

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

Final Applicant Cover letter.dot 11/30/07

Mail Code 61-53

IDEM Staff	MIDENNEY 6/26/2009 Countrymark Cooperative, LLP 129-28028-00003 (final)		AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶ Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Jim Pankey Countrymark Cooperative, LLP 1200 Refinery Rd Mount Vernon IN 47620 (Source CAATS) via confirmed delivery									
2		Matthew L Smorch Refinery Mgr Countrymark Cooperative, LLP 1200 Refinery Rd Mount Vernon IN 47620 *(RO CAATS)*									
3		Mr. Charles L. Berger Berger & Berger, Attorneys at Law 313 Main Street Evansville IN 47700 *(Affected Party)*									
4		Mr. Randy Brown Plumbers & Steam Fitters Union, Local 136 2300 St. Joe Industrial Park Dr Evansville IN 47720 *(Affected Party)*									
5		Posey County Commissioners County Courthouse, 126 E. 3rd Street Mount Vernon IN 47620 *(Local Official)*									
6		Posey County Health Department 126 E. 3rd St, Coliseum Bldg Mount Vernon IN 47620-1811 *(Health Department)*									
7		Mount Vernon City Council and Mayors Office 520 Main Street Mount Vernon IN 47620 *(Local Official)*									
8		Dr. Jeff Seyler Univ. of So Ind., 8600 Univ. Blvd. Evansville IN 47712 *(Affected Party)*									
9		Mr. Don Mottley Save Our Rivers 6222 Yankeetown Hwy Boonville IN 47601 *(Affected Party)*									
10		Mrs. Connie Parkinson 510 Western Hills Dr. Mt. Vernon IN 47620 *(Affected Party)*									
11		Robert Hess c/o Mellon Corporation 830 Post Road East, Suite 105 Westport CT 06880 *(Affected Party)*									
12		Juanita Burton 7911 W. Franklin Road Evansville IN 47712 *(Affected Party)*									
13		Mr. John Blair 800 Adams Ave Evansville IN 47713 (Affected Party)									
14		Pat Sorensen Environmental Resources Management (ERM) 11350 North Meridian Street, Suite 320 Carmel IN 46032 *(Consultant)*									
15											

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