Mitchell E. Daniels, Jr.
Governor

Thomas W. Easterly
Commissioner

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

TO: Interested Parties / Applicant

DATE: December 8, 2006

RE: Countrymark Cooperative, LLP / 129-22917-00003

FROM: Nisha Sizemore
Chief, Permits Branch
Office of Air Quality

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Room 1049, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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.dot 03/23/06

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Mitchell E. Daniels, Jr.
Governor

Thomas W. Easterly
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Mr. Dave Hertzing
Countrymark Cooperative, LLP
1200 Refinery Road
Mount Vernon, IN 47620

December 8, 2006

Re: 129-22917-00003
Second Significant Source Modification to
Part 70 Permit No.: 129-7882-00003

Dear Mr. Hertzing:

Countrymark Cooperative, LLP was issued a Part 70 permit on July 21, 2003, for the operation of a petroleum refinery. An application to modify the source was received by the Office of Air Quality (OAQ) on April 04, 2006. Pursuant to the provisions of 326 IAC 2-7-10.5 the following emission units are approved for construction at the source:

(a) One (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 MMBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 MMBtu/hr), constructed in 1945 and modified in 2006 and exhausting to stack 18;

(b) One (1) fixed roof, insulated, heated cone tank, identified as Tank No. 22B, with a capacity of 1,050,000 gallons and a maximum withdrawal rate of 16,800 gallons per hour of petroleum or residual fuel oil (No.6) with vapor pressure of No. 2 fuel oil or less and exhausting to stack 127 (start construction in second quarter of 2006 and to be completed by November 2006);

(c) One (1) fixed roof, insulated, heated cone tank, identified as Tank No. 173, with a capacity of 1,050,000 gallons and a maximum withdrawal rate of 16,800 gallons per hour of petroleum or residual fuel oil (No.6) with vapor pressure of No. 2 fuel oil or less and exhausting to stack 128 (start construction in third quarter of 2006 and to be completed by March 2007);

(d) One (1) fixed roof, insulated, heated cone tank, identified as Tank No. 174, with a capacity of 1,050,000 gallons and a maximum withdrawal rate of 16,800 gallons per hour of petroleum or residual fuel oil (No.6) with vapor pressure of No. 2 fuel oil or less and exhausting to stack 129 (start construction in second quarter of 2007 and to be completed by December 2007); and

(e) 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).

(f) One (1) boiler identified as B4, 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 following construction conditions are applicable to the proposed project:

General Construction Conditions

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

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

3. Effective Date of the Permit
Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

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

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

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

This significant source modification authorizes construction of the new emission units. Operating conditions shall be incorporated into the Part 70 operating permit as a significant permit modification in accordance with 326 IAC 2-7-10.5(l)(2) and 326 IAC 2-7-12. Operation is not approved until the significant permit modification has been issued.

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 call Surya Ramaswamy at (973) 575-2555, ext. 3216 or dial (800) 451-6027, and ask for extension 3-6878.

Sincerely,

Nisha Sizemore

Nisha Sizemore, Chief
Permit Branch
Office of Air Quality

Attachments
Technical Support Document
Revised Part 70 permit pages

KSR/EVP

cc: File – Posey County
U.S. EPA, Region V

Compliance Data Section
Administrative and Development
Technical Support and Modeling - Michele Boner

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PART 70 SIGNIFICANT SOURCE MODIFICATION
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

First Minor Source Modification No. 129-18135-00003, issued on November 17, 2003
First Significant Permit Modification No. 129-17940-00003, issued on November 24, 2003
First Significant Source Modification No. 129-18672-00003, issued on February 1, 2005
Second Significant Permit Modification No. 129-20112-00003, issued on March 21, 2005
First Administrative Amendment No. 129-20343-00003, issued on March 30, 2005.
Third Significant Permit Modification: SPM 129-21251-00003, issued on August 15, 2005

Significant Source Modification: SSM 129-22917-00003	
Issued by: Nisha Sizemore Nisha Sizemore, Chief Permits Branch Office of Air Quality	Issuance Date: **December 8, 2006**

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1, A.3, and A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

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

The Permittee owns and operates a stationary petroleum refinery.

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

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

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

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

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

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

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

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

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

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

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

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

(d) The following storage vessels:

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
1	fixed roof cone tank	404,418	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet 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	082;
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	037;
19	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	616,938	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	032;
21	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	1,002,750	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	034;
22A	fixed roof cone tank	1,050,000	84,000	hydrocarbon with vapor pressure of No. 2 fuel oil o less	2003	120;
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;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
24	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	588,714	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1985	037;
25	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	656,614	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	038;
26	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	1,006,068	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	039;
33	fixed roof cone tank	2,262,960	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet 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;
36	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,261,954	336,000	hydrocarbon with vapor pressureequal to or less than the vaporpressure 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	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1949	051;
41	fixed roof cone tank/internal floating roof tank,/lmechanical primary seal	2,204,244	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1949	052;
42	fixed roof cone tank	2,261,574	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet 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	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;
Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID

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	063;
53	fixed roof cone tank	16,926	168,000	Ethanol,	1985	086;
54	fixed roof cone tank	16,926	168,000	Ethanol,	1985	087;
55	fixed roof cone tank	11,634	168,000	Ethanol,	1980	088;
56	fixed roof cone tank	11,634	168,000	Ethanol,	1980	089;
58	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1980	102;
159	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	103;
160	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	104;
161	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	105;
162	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	106;
163	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1983	107;
164	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1983	108;
165	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	109;
166	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	110;
167	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	111;
168	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	112;
169	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1989	113;
125	fixed roof cone tank	157,000	6,000	hydrocarbon with vapor pressure of No.2 fuel oil or less	2005	015;
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;
Tank ID	**Tank Description**	**Max. Capacity (gallons)**	**Max. Withdrawal Rate (gal/hr)**	**Material Stored**	**Construction Date**	**Stack ID**
175	fixed roof cone tank/internal floating roof tank,/liquid mounted primary seal	2,310,000	210,000	Petroleum Material with a vapor pressure equivalent to or less than the vapor pressure of 13 rvp gasoline,	2007	130

(e) one (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 and replaced in 2006 and exhausting to stack 118;
(f) one (1) Crude heater equipped with a Low-NOx burner, identified as C-II with a maximum heat input rate of 131 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1955 and exhausting to stack 1;
(g) one (1) Unifiner heater, identified as H-H5 with a maximum heat input rate of 20 mmBtu/hr, combusting refinery fuel gas, installed in 1959 and exhausting to stack 2;
(h) one (1) Cycle oil heater, identified as H-H2 with a maximum heat input rate of 10 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 3;
(i) one (1) Naphtha splitter heater, identified as H-H3 with a maximum heat input rate of 12.2 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 4;
(j) one (1) Vacuum heater, identified as V-IV with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950 and exhausting to stack 5;
(k) one (1) Old Platformer heater, identified as P-H1 with a maximum heat input rate of 29 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 6;
(l) one (1) Alkylation unit heater, identified as A-H1 with a maximum heat input rate of 13.2 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1966 and exhausting to stack 7;
(m) one (1) Auxiliary crude heater, identified as C-I with a maximum heat input rate of 10.1 mmBtu/hr, combusting refinery fuel gas, installed in 1966 and exhausting to stack 11;
(n) one (1) Platformer stabilizer reb, identified as P-H2 with a maximum heat input rate of 5.92 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 12;
(o) one (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;
(p) one (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;
(q) one (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;
(r) one (1) Vacuum heater husky, identified as VIII with a maximum heat input rate of 6.27 mmBtu/hr, combusting refinery fuel gas No. 6 residual fuel oil,, installed in 1963 and exhausting to stack 64;
(s) one (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74;
(t) two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071;
(u) one (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;
(v) pipeline Valves - Gas, identified as 090;
(w) pipeline Valves - Light Liquid, identified as 091;
(x) pipeline Valves - Heavy Liquid, identified as 092;
(y) pipeline Valves - Hydrogen, identified as 093;
(z) open Ended Valves, identified as 094;
(aa) flanges, identified as 095;
(bb) pump Seals Light Liquid, identified as 096;
(cc) pump Seals Heavy Liquid, identified as 097;
(dd) compressor Seals - Gas, identified as 098;
(ee) compressor Seals - Heavy Liquid, identified as 099;
(ff) drains, identified as 100;
(gg) vessel Relief Valves, identified as 101;
(hh) cooling Towers, identified as 119; and
(ii) process units made up of vessels, piping, exchangers, identified as PENEX.
(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a

maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (to be constructed in 2005).

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

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:
- (1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).
- (2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.
- (3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).
- (4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of:
- (1) pipeline Valves - Gas, identified as 090;
- (2) pipeline Valves - Light Liquid, identified as 091;
- (3) pipeline Valves - Heavy Liquid, identified as 092;
- (4) pipeline Valves - Hydrogen, identified as 093;
- (5) open Ended Valves, identified as 094;
- (6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
- (7) flanges, identified as 095;
- (8) pump Seals Light Liquid, identified as 096;
- (9) pump Seals Heavy Liquid, identified as 097;
- (10) compressor Seals - Gas, identified as 098;
- (11) compressor Seals - Heavy Liquid, identified as 099;
- (12) drains, identified as 100;
- (13) vessel Relief Valves, identified as 101; and
- (14) cooling Towers, identified as 119.

(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 Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (40 CFR 63, Subpart DDDDD), the boiler B4, is considered an existing affected source. The boiler is categorized under the large liquid fuel subcategory.

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.

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 Branch, Office of Air Quality
100 North Senate Avenue
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 Branch, Office of Air Quality
100 North Senate Avenue
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 Branch, Office of Air Quality
100 North Senate Avenue
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.

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 Data Section, Office of Air Quality
100 North Senate Avenue
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
Permits Branch, Office of Air Quality
100 North Senate Avenue
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
Permits Branch, Office of Air Quality
100 North Senate Avenue
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
Permits Branch, Office of Air Quality
100 North Senate Avenue
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
Permits Branch, Office of Air Quality
100 North Senate Avenue
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
Asbestos Section, Office of Air Quality
100 North Senate Avenue
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 Data Section, Office of Air Quality
100 North Senate Avenue
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 Branch, Office of Air Quality
100 North Senate Avenue
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 Branch, Office of Air Quality
100 North Senate Avenue
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 and 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
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](Select citations as applicable)

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

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

C.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](Select citations as applicable)

(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 Data Section, Office of Air Quality
100 North Senate Avenue
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.

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 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(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;

(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 tank's 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 (Δp) 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 inaccordance 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 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74;
(b) One (1) FCCU regenerator, identified as V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10;
(c) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (to be constructed in 2005);
(d) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 (to be constructed in 2005);
(e) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:
    (1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).
    (2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.
    (3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).
    (4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).
(f) 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 Permitte shall comply with each applicable emission limitation in Table 22 of this subpart. These emission limitations apply during coke burn-off and catalyst rejuvenation. The Permittee must choose a compliance option from the two options listed in 40 CFR 63.1567 paragraphs (a)(1)(i) through (ii).
   (2) The Permittee shall comply with each applicable site-specific operating limit in Table 23 of this subpart. These operating limits apply during coke burn-off and catalyst rejuvenation.
   (3) The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in 40 CFR 63.1574(f) and operate at all times according to the procedures in the plan.

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

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

(a) Pursuant to 40 CFR 63.1568, the following emission limitations and work practice standards shall apply to the Sulfur Recovery Unit and TGTU:

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

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

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

(a) Pursuant to 40 CFR 63.1569, the following emission limitations and work practice standards shall apply to the bypass lines:
    (1) The Permittee shall meet each work practice standard in Table 36 of this subpart. The Permittee can choose from the four options in paragraphs (a)(1)(i) through (iv) of 40 CFR 63.1569:
        (i) The Permittee can elect to install an automated system (Option 1);
        (ii) The Permittee can elect to use a manual lock system (Option 2);
        (iii) The Permittee can elect to seal the line (Option 3); or
        (iv) The Permittee can elect to vent to a control device (Option 4).
    (2) As provided in § 63.6(g), the EPA, may choose to grant permission to use an alternative to the work practice standard in paragraph (a)(1) of 40 CFR 63.1569.
    (3) The Permittee must prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.
(b) To demonstrate continuous compliance with the emission limitations and work practice standards, the Permittee shall:
    (1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies according to the requirements in Table 39 of this subpart.
    (2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of 40 CFR 63.1569 by complying with the procedures in the operation, maintenance, and monitoring plan.

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

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

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

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

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

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

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

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

D.2.15 Performance Testing [40 CFR 60.106]

During the period between 60 and 180 days following the effective date of becoming subject to the rule 40 CFR 60.104, in order to demonstrate compliance with Condition D.2.5, the Permittee shall perform H_2S testing for the CCR Platformer Heater, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), 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 demostrate initial compliance with the emission limitations and work practice standards for Inorganic HAP Emissions from Catalytic Reforming unit (CCR) by:
  (1) Installing, operating, and maintaining a continuous monitoring system(s) according to the requirements in 40 CFR 63.1572 and Table 24 of this subpart.
  (2) Conducting each performance test for a catalytic reforming unit according to the requirements in 40 CFR 63.1571 and the conditions specified in Table 25 of this subpart.
  (3) Establishing each applicable site-specific operating limit in Table 23 of this subpart according to the procedures in Table 25 of this subpart.
  (4) Demonstrating initial compliance with each applicable emission limitation according to Table 26 of this subpart.
  (5) Demonstrating initial compliance with the work practice standard in 40 CFR 63.1567 paragraph (a)(3) by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the Notification of Compliance Status.
  (6) Submitting the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.1574.

(e) To demonstrate initial compliance with the emission limitations and work practice standards for Sulfur Recovery Units, the Permittee shall:
  (1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 31 of this subpart.
  (2) Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in § 63.1571 and under the conditions specified in Table 32 of this subpart.
  (3) Establish each site-specific operating limit in Table 30 of this subpart that applies according to the procedures in Table 32 of this subpart.
  (4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of 40 CFR 63.1568.
  (5) Demonstrate initial compliance with each emission limitation that applies according to Table 33 of this subpart.
  (6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of 40 CFR 63.1568 by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of notification of compliance status.
  (7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(f) To demonstrate initial compliance with the emission limitations and work practice standards for Bypass Lines, the Permittee shall:
  (1) If the Permittee elects the option in paragraph (a)(1)(i) of 40 CFR 63.1569, conduct

each performance test for a bypass line according to the requirements in § 63.1571 and under the conditions specified in Table 37 of this subpart.

(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies according to Table 38 of this subpart.

(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this 40 CFR 63.1569 by submitting the operation, maintenance, and monitoring plan to IDEM, OAQ as part of the notification of compliance status.

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

D.2.17 Performance Testing [40 CFR 63.1571]

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

(1) For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, the Permittee shall conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for the source in 40 CFR 63.1563.

(2) For each emission limitation where the averaging period is 30 days, the 30-day period for demonstrating initial compliance begins at 12:00 a.m. on the compliance date that is specified for the source in 40 CFR 63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for the source in 40 CFR 63.1563.

(b) The Permittee shall:

(1) Conduct each performance test according to the requirements in 40 CFR 63.7(e)(1).

(2) Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in 40 CFR 63.7(e)(3). Each test run must last at least 1 hour.

(3) Conduct each performance evaluation according to the requirements in 40 CFR 63.8(e).

(4) Not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 40 CFR 63.7(e)(1).

(5) Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5, or 8 of 40 CFR 63.1564, and determining the arithmetic average of the calculated emission rates.

(c) The Permittee may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If the Permittee uses an engineering assessment, the Permittee shall document all data, assumptions, and procedures to the satisfaction of IDEM, OAQ. An engineering assessment may include the approaches listed in 40 CFR 63.1571 paragraphs (c)(1) through (c)(4). Other engineering assessments may be used but are subject to review and approval by IDEM, OAQ.

(1) The Permittee may use previous test results provided the tests are representative of

current operating practices at the process unit, and provided EPA methods or approved alternatives were used;

(2) the Permittee may use bench-scale or pilot-scale test data representative of the process under representative operating conditions;

(3) the Permittee may use maximum flow rate, TOC emission rate, organic HAP emission rate, or organic HAP or TOC concentration specified or implied within a permit limit applicable to the process vent; or

(4) the Permittee may use design analysis based on engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(i) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(ii) Calculation of hourly average maximum flow rate based on physical equipment design such as pump or blower capacities; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D.2.19 Continuous Monitoring [40 CFR 60.105]

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

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

(1) The fuel gas must be sampled every 8 hours during the unit's operation at the representative location and analyze the 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 Permitte also shall report each instance in which the Permittee did not meet the applicable work practice standards in this subpart. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in 40 CFR 63.1575.

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

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

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

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

(c) The Permittee shall install, operate, and maintain each continuous parameter monitoring system according to the requirements in 40 CFR 63.1572 paragraphs (c)(1) through (7).
    (1) Each continuous parameter monitoring system must be installed, operated, and maintained according to the requirements in Table 41 of this subpart and in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately.
    (2) The continuous parameter monitoring system must complete a minimum of one

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

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

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

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

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

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

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

D.2.22 General Compliance Requirements [40 CFR 63.7505]

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

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

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

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

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

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

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

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(2) In the site-specific monitoring plan, the Permittee must also address paragraphs (d)(2)(i) through (iii) of this 40 CFR 63.7505.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (3), and (4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

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

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

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

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

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

(a) If the Permittee has an applicable work practice standard for carbon monoxide, and the boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, then the Permittee must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of 40 CFR 63.7525 by the compliance date specified in §63.7495.

(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to §63.7505(d).

(2) The Permittee must conduct a performance evaluation of each CEMS according to the requirements in §63.8 and according to PS 4A of 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in §63.8(g)(2).

(5) The Permittee must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, the Permittee must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when the boiler or process heater is operating at less than 50 percent of its rated capacity. The Permittee must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitute a deviation from the monitoring requirements.

(b) If the Permittee has an applicable opacity operating limit, then the Permittee must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of 40 CFR 63.7525 by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.

(2) The Permittee must conduct a performance evaluation of each COMS according to the requirements in §63.8 and according to PS 1 of 40 CFR part 60, appendix B.

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(e) If the Permittee has an operating limit that requires the use of a pressure measurement device, then the Permittee must meet the requirements in paragraphs (c) and (e)(1) through (6) of 40 CFR 63.7525.
(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.
(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.
(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.
(4) Check pressure tap pluggage daily.
(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.
(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(f) If the Permittee has an operating limit that requires the use of a pH measurement device, then the Permittee must meet the requirements in paragraphs (c) and (f)(1) through (3) of this 40 CFR 63.7525.
(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.
(2) Ensure the sample is properly mixed and representative of the fluid to be measured.
(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

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

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

(i) If the Permittee elects to use a fabric filter bag leak detection system to comply with the requirements of this subpart, then the Permittee must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of 40 CFR 63.7525.
(1) The Permittee must install and operate a bag leak detection system for each exhaust stack of the fabric filter.
(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA-454/R-98-015, September 1997.

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per

actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

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

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

(a) The 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 H_2S in fuel gases by methods defined under Condition D.2.19.

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

D.2.27 Record Keeping Requirements [40 CFR 63.1576]

(a) The Permittee shall keep the records specified in 40 CFR 63.1576 paragraphs (a)(1) through (3).

(1) A copy of each notification and report that the Permittee submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status that the Permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).

(2) The records in 40 CFR 63.6(e)(1)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in 40 CFR 63.10(b)(2)(viii).

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

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

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

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

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

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

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

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

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

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

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

(a) Except as allowed in 40 CFR 63.1574 paragraphs (a)(1) through (3), the Permittee shall submit all of the applicable notifications in 40 CFR 63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) by the dates specified below.
(1) The Permittee shall submit the notification of intention to construct or reconstruct according to 40 CFR 63.9(b)(5).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Company name and address.
(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
(3) Date of report and beginning and ending dates of the reporting period.
(4) If there are no deviations from any applicable emission limitation and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

(d) For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where the Permittee is not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the compliance report must contain the information in 40 CFR 63.1576 paragraphs (c)(1) through (3) and the information in 40 CFR 63.1576 paragraphs (d)(1) through (3).
(1) The total operating time of each affected source during the reporting period.
(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.
(3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(e) For each deviation from an emission limitation occurring at an affected source where the Permittee is using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, the Permittee shall include the information in 40 CFR 63.1576 paragraphs (d)(1) through (3) and the information in 40 CFR 63.1576 paragraphs (e)(1) through (13).
(1) The date and time that each malfunction started and stopped.
(2) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high-level checks.
(3) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in 40 CFR 63.8(c)(8).
(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.
(5) A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during that reporting period.
(6) A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.
(7) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.

(8) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into

periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.

(9) An identification of each HAP that was monitored at the affected source.

(10) A brief description of the process units.

(11) The monitoring equipment manufacturer(s) and model number(s).

(12) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.

(13) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.

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

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

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

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

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

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

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

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

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

(2) In the compliance report due after the routine planned maintenance is complete, the Permittee must include a description of the planned routine maintenance that was

performed for the control device during the previous 6-month period, and the total number of hours during those 6 months that the control device did not meet the emission limitations and monitoring requirements as a result of the approved routine planned maintenance.

(j) If Permittee owns or operates multiple catalytic cracking units that are served by a single wet scrubber emission control device (e.g., a Venturi scrubber), the Permittee may request IDEM, OAQ to approve a period of planned routine maintenance for the control device needed to meet requirements in the operation, maintenance, and monitoring plan. The Permittee must present data to IDEM, OAQ demonstrating that the period of planned maintenance results in overall emissions reductions. During this pre-approved time period, the emission control device may be taken out of service while maintenance is performed on the control device and/or one of the process units while the remaining process unit(s) continue to operate. During the period the emission control device is unable to operate, the emission limits, operating limits, and monitoring requirements applicable to the unit that is operating and the wet scrubber emission control device do not apply. IDEM, OAQ may require that the Permittee take specified actions to minimize emissions during the period of planned maintenance.
(1) The Permittee must submit a written request to IDEM, OAQ at least 6 months before the planned maintenance is scheduled to begin with a copy to the EPA Regional Administrator.
(2) Permittee's written request must contain the information in 40 CFR 63.1575 paragraphs (j)(2)(i) through (v).
(i) A description of the planned routine maintenance to be performed during the next 6 months and why it is necessary.
(ii) The date the planned maintenance will begin and end.
(iii) A quantified estimate of the HAP and criteria pollutant emissions that will be emitted during the period of planned maintenance.
(iv) An analysis showing the emissions reductions resulting from the planned maintenance as opposed to delaying the maintenance until the next unit turnaround.
(v) Actions the Permittee will take to minimize emissions during the period of planned maintenance.

D.2.30 Notification Requirements [40 CFR Part 63.7545]

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

(a) The Permittee must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply by the dates specified.
(b) As specified in §63.9(b)(2), if the Permitte startup the affected source before the date of publication of the final rule in the federal register, the Permittee must submit an Initial Notification not later than 120 days after the date of publication of the final rule in the federal register. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of 40 CFR 63.7545, as applicable.
(1) If the affected source has an annual capacity factor of greater than 10 percent, then the Initial Notification must include the information required by §63.9(b)(2).
(2) If the affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), then the Initial Notification must include the information required by §63.9(b)(2) and also a signed statement indicating that affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

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

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

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

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

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

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

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

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

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

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

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

(b) For each CEMS, CPMS, and COMS, the Permittee must keep records according to paragraphs (b)(1) through (5) of 40 CFR 63.7555.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

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

(d) For each boiler or process heater subject to an emission limit, the Permittee must also keep the records in paragraphs (d)(1) through (5) of 40 CFR 63.7555.

(1) The Permittee must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) The Permittee must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 1 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 5 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 2 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 6 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. The Permittee can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, the Permittee must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

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

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

(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(2) Fuel use records for the days the boiler or process heater was operating.

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

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

(h) The Permittee must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to

§63.10(b)(1). The Permittee can keep the records off site for the remaining 3 years.

D.2.32 Reporting Requirements [40 CFR Part 63.7550]

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

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

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

(1) The first compliance report must cover the period beginning on the compliance date that is specified for the affected source in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for the source in §63.7495.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in §63.7495.

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

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

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the Permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of 40 CFR 63.7550.

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

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

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

(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which the Permittee deviated.

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

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

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

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

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

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

The following storage vessels:

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

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
1	fixed roof cone tank	404,418	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet 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	082;
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	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;

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
22A	fixed roof cone tank	1,050,000	84,000	hydrocarbon with vapor pressure of No. 2 fuel oil o less	2003	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	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;
36	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,261,954	336,000	hydrocarbon with vapor pressureequal to or less than the vaporpressure 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	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1949	051;
41	fixed roof cone tank/internal floating roof tank,/lmechanical primary seal	2,204,244	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1949	052;
42	fixed roof cone tank	2,261,574	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet 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	058;
Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID

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	063;
53	fixed roof cone tank	16,926	168,000	Ethanol,	1985	086;
54	fixed roof cone tank	16,926	168,000	Ethanol,	1985	087;
55	fixed roof cone tank	11,634	168,000	Ethanol,	1980	088;
56	fixed roof cone tank	11,634	168,000	Ethanol,	1980	089;
58	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1980	102;
159	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	103;
160	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	104;
161	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	105;
162	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1994	106;
163	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1983	107;
164	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1983	108;
165	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	109;
166	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	110;
167	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1985	111;
168	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	112;
169	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1989	113;
125	fixed roof cone tank	157,000	6,000	hydrocarbon with vapor pressure of No.2 fuel oil or less	2005	015;
Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	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

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) 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 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 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

(The information describing the process contained in this 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 judgement or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

of Subpart H of this part.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Within the first 12 months after the phase III compliance date specified in 40 CFR 63.640(h), a sample of 200 connectors shall be randomly selected and monitored using Method 21 of 40 CFR part 60, appendix A.
(2) The instrument reading that defines a leak is 1,000 parts per million.
(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in 40 CFR 63.649 paragraph (e). A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.
(4) If a leak is detected, the connector shall be monitored for leaks within the first 3 months after its repair.
(5) After conducting the initial survey required in 40 CFR 63.649 paragraph (b)(1), the Permittee shall conduct subsequent monitoring of connectors at the frequencies specified in 40 CFR 63.649 paragraphs (b)(5)(i) through (b)(5)(iv).
(6) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) (1) Each drain shall be equipped with water seal controls.
(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.
(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low
(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.
(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in Sec. 60.692-6.

(b) (1) Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
(2) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
(3) Junction boxes shall be visually inspected initially and semiannually hereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(4) If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in Sec. 60.692-6.

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

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

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

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

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

(a) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in 40 CFR 60.693-2.
(1) The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.
(2) The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.
(3) If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.
(4) Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.
(5) When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in Sec. 60.692-6.
(b) Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph (a) of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of Sec. 60.692-5, except as provided in paragraph (c) of this section or in Sec. 60.693-2.
(c) (1) Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of paragraph (b) of this section, but shall meet the requirements of paragraph (a) of this section, or may elect to comply with paragraph (c)(2) of

this section.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D.4.17 Standards for Closed Vent Systems and Control Devices [40CFR 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 [40CFR 60.696] [326 IAC 12]

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

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

(b) The Permittee of each source that is equipped with a closed vent system and control device as required in Sec. 60.692-5 (other than a flare) is exempt from Sec. 60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

(1) Zero air (less than 10 ppm of hydrocarbon in air), and

(2) A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

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

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

(1) The maximum gap widths and maximum gap areas between the primary seal and the separator wall and between the secondary seal and the separator wall shall be determined individually within 60 calendar days of the initial installation of the floating roof and introduction of refinery wastewater or 60 calendar days after the equipment is placed back into service using the following procedure when the separator is filled to the design operating level and when the roof is floating off the roof supports.
   (i) Measure seal gaps around the entire perimeter of the separator in each place where a 0.32 cm (0.125 in.) diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the separator and measure the gap width and perimetrical distance of each such location.
   (ii) The total surface area of each gap described in (d)(1)(i) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the wall to the seal and multiplying each such width by its respective perimetrical distance.
   (iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually, divide the sum for each seal by the nominal perimeter of the separator basin and compare each to the maximum gap area as specified in Sec. 60.693-2.
(2) The gap widths and total gap area shall be determined using the procedure in paragraph (d)(1) of this section according to the following frequency:
   (i) For primary seals, once every 5 years.
   (ii) For secondary seals, once every year.

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

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

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

(a) For each emission point included in an emissions average, the Permittee shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with 40 CFR 63.643 through 63.647, and 40 CFR 63.650 and 63.651. The specific requirements for storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in 40 CFR 63.653 paragraphs (a)(3), (a)(4) and (a)(7).
   (1) The source shall implement the following procedures for each storage vessel controlled with an internal floating roof, external roof, or a closed vent system with a control device, as appropriate to the control technique:
      (i) Perform the monitoring or inspection procedures in 40 CFR 63.646 of this subpart and 40 CFR 63.120 of Subpart G; and
      (ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in 40 CFR 63.646 of this subpart and 40 CFR 63.120(d) of Subpart G.
   (2) For each gasoline loading rack that is controlled, perform the testing and monitoring procedures specified in 40 CFR 63.425 and 63.427 of Subpart R of this part except 40 CFR 63.425(d) or 40 CFR 63.427(c).
   (3) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in 40 CFR 63.643 through 63.647 and 40 CFR 63.650 and 63.651, the Permittee shall establish a site-specific monitoring parameter and shall submit the information specified in 40 CFR 63.654(h)(4) in

the Implementation Plan.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) Each Permittee subject to the gasoline loading rack provisions in 40 CFR 63.650 shall comply with the recordkeeping and reporting provisions in 40 CFR 63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of Subpart R of this part (listed in section D.1). These requirements are summarized in table 4 of this subpart. There are no additional reporting and recordkeeping requirements for gasoline loading racks under this subpart unless a loading rack is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in 40 CFR 63.653 and in 40 CFR 63.654 paragraphs (f)(5) and (g)(8).

(b) Each Permittee subject to the equipment leaks standards in 40 CFR 63.648 shall comply with the recordkeeping and reporting provisions in 40 CFR 63.654 paragraphs (d)(1) through (d)(6).

(1) 40 CFR 60.486 and 60.487 of Subpart VV of part 60 except as specified in 40 CFR 63.654 paragraph (d)(1)(i); or 40 CFR 63.181 and 63.182 of Subpart H of this part except for 40 CFR 63.182(b), (c)(2), and (c)(4).

(i) The signature of the Permittee (or designate) whose decision it was that a repair could not be effected without a process shutdown is not required to be recorded. Instead, the name of the person whose decision it was that a repair could not be effected without a process shutdown shall be recorded and retained for 2 years.

(2) The Notification of Compliance Status report required by 40 CFR 63.182(c) of Subpart H and the initial semiannual report required by 40 CFR 60.487(b) of 40 CFR part 60, Subpart VV shall be submitted within 150 days of the compliance date specified in 40 CFR 63.640(h); the requirements of Subpart H of this part are summarized in table 3 of this subpart.
(3) A Permittee who determines that a compressor qualifies for the hydrogen service exemption in 40 CFR 63.648 shall also keep a record of the demonstration required by 40 CFR 63.648.
(4) A Permittee must keep a list of identification numbers for valves that are designated as leakless per 40 CFR 63.648(c)(10).
(5) A Permittee must identify, either by list or location (area or refining process unit), equipment in organic HAP service less than 300 hours per year within refining process units subject to this subpart.
(6) A Permittee must keep a list of reciprocating pumps and compressors determined to be exempt from seal requirements as per 40 CFR 63.648 (f) and (i).

(c) Each Permittee of a source subject to this subpart shall submit the reports listed in 40 CFR 63.654 paragraphs (e)(1) through (e)(3) except as provided in 40 CFR 63.654 paragraph (h)(5), and shall keep records as described in 40 CFR 63.654 paragraph (i).
(1) A Notification of Compliance Status report as described in 40 CFR 63.654 paragraph (f);
(2) Periodic Reports as described in 40 CFR 63.654 paragraph (g); and
(3) Other reports as described in 40 CFR 63.654 paragraph (h).

(d) Each Permittee of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in 40 CFR 63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with 40 CFR 63.640(l)(3) and for storage vessels subject to the compliance schedule specified in 40 CFR 63.640(h)(4). Notification of Compliance Status reports required by 40 CFR 63.640(l)(3) and for storage vessels subject to the compliance dates specified in 40 CFR 63.640(h)(4) shall be submitted according to 40 CFR 63.654 paragraph (f)(6). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in 40 CFR 63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in 40 CFR 63.640(h). If a Permittee submits the information specified in 40 CFR 63.654 paragraphs (f)(1) through (f)(5) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. Each Permittee of a gasoline loading rack classified under Standard Industrial Classification Code 2911 located within a contiguous area and under common control with a petroleum refinery subject to the standards of this subpart shall submit the Notification of Compliance Status report required by Subpart R of this part within 150 days after the compliance dates specified in 40 CFR 63.640(h) of this subpart.
(1) The Notification of Compliance Status report shall include the information specified in 40 CFR 63.654 paragraphs (f)(1)(i) and (f)(1)(v).
(i) For storage vessels, this report shall include the information specified in 40 CFR 63.654 paragraphs (f)(1)(i)(A) through (f)(1)(i)(D).

(A) Identification of each storage vessel subject to this subpart, and for each Group 1 storage vessel subject to this subpart, the information specified in 40 CFR 63.654 paragraphs (f)(1)(i)(A)(1) through (f)(1)(i)(A)(3). This information is to be revised each time a Notification of Compliance Status report is submitted for a storage vessel subject to the compliance schedule specified in 40 CFR 63.640(h)(4) or to comply with 40 CFR 63.640(l)(3).

(aa) For each Group 1 storage vessel complying with 40 CFR 63.646 that is not included in an emissions average, the method of compliance (i.e., internal floating roof, external floating roof, or closed vent system and control device).

(bb) For storage vessels subject to the compliance schedule specified in 40 CFR 63.640(h)(4) that are not complying with 40 CFR 63.646, the anticipated compliance date.

(cc) For storage vessels subject to the compliance schedule specified in 40 CFR 63.640(h)(4) that are complying with 40 CFR 63.646 and the Group 1 storage vessels described in 40 CFR 63.640(l), the actual compliance date.

(B) If a closed vent system and a control device other than a flare is used to comply with 40 CFR 63.646 the Permittee shall submit:

(aa) A description of the parameter or parameters to be monitored to ensure that the control device is being properly operated and maintained, an explanation of the criteria used for selection of that parameter (or parameters), and the frequency with which monitoring will be performed; and either

(bb) The design evaluation documentation specified in 40 CFR 63.120(d)(1)(i) of Subpart G, if the Permittee elects to prepare a design evaluation; or

(cc) If the Permittee elects to submit the results of a performance test, identification of the storage vessel and control device for which the performance test will be submitted, and identification of the emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted.

(C) If a closed vent system and control device other than a flare is used, the Permittee shall submit:

(aa) The operating range for each monitoring parameter. The specified operating range shall represent the conditions for which the control device is being properly operated and maintained.

(bb) If a performance test is conducted instead of a design evaluation, results of the performance test demonstrating that the control device achieves greater than or equal to the required control efficiency. A performance test conducted prior to the compliance date of this subpart can be used to comply with this requirement, provided that the test was conducted using EPA methods and that the test conditions are representative of current operating practices.

(D) If a closed vent system and a flare is used, the Permittee shall submit:

(aa) Flare design (e.g., steam-assisted, air-assisted, or nonassisted);

(bb) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by 40 CFR 63.120(e) of Subpart G of this part; and

(cc) All periods during the compliance determination when the pilot flame is absent.

(ii) For equipment leaks complying with 40 CFR 63.648(c) (i.e., complying with the requirements of Subpart H of this part), the Notification of Compliance Report Status report information required by 40 CFR 63.182(c) of Subpart H and whether the percentage of leaking valves will be reported on a process unit basis or a sourcewide basis.

(2) If initial performance tests are required by 40 CFR 63.643 through 63.653 of this subpart, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source.

(i) For additional tests performed using the same method, the results specified in 40 CFR 63.654 paragraph (f)(1) shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(iii) Performance tests are required only if specified by 40 CFR 63.643 through 63.653 of this subpart. Initial performance tests are required for some kinds of emission points and controls. Periodic testing of the same emission point is not required.

(3) For each monitored parameter for which a range is required to be established under 40 CFR 63.120(d) of Subpart G of this part for storage vessels, the Notification of Compliance Status report shall include the information in 40 CFR 63.654 paragraphs (f)(3)(i) through (f)(3)(iii).

(i) The specific range of the monitored parameter(s) for each emission point;

(ii) The rationale for the specific range for each parameter for each emission point, including any data and calculations used to develop the range and a description of why the range ensures compliance with the emission standard.

(A) If a performance test is required by this subpart for a control device, the range shall be based on the parameter values measured during the performance test supplemented by engineering assessments and manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of permitted parameter values.

(B) If a performance test is not required by this subpart for a control device, the range may be based solely on engineering assessments and manufacturers' recommendations.

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(4) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report.

(5) For emission points included in an emissions average, the Notification of Compliance Status report shall include the values of the parameters needed for

input to the emission credit and debit equations in 40 CFR 63.652(g) and (h), calculated or measured according to the procedures in 40 CFR 63.652(g) and (h), and the resulting credits and debits for the first quarter of the year. The first quarter begins on the compliance date specified in 40 CFR 63.640.

(6) Notification of Compliance Status reports required by 40 CFR 63.640(l)(3) and for storage vessels subject to the compliance dates specified in 40 CFR 63.640(h)(4) shall be submitted no later than 60 days after the end of the 6-month period during which the change or addition was made that resulted in the Group 1 emission point or the existing Group 1 storage vessel was brought into compliance, and may be combined with the periodic report. Six-month periods shall be the same 6-month periods specified in 40 CFR 63.654 paragraph (g). The Notification of Compliance Status report shall include the information specified in 40 CFR 63.654 paragraphs (f)(1) through (f)(5). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, as part of the periodic report, or in any combination of these four. If the required information has been submitted before the date 60 days after the end of the 6-month period in which the addition of the Group 1 emission point took place, a separate Notification of Compliance Status report is not required within 60 days after the end of the 6-month period. If a Permittee submits the information specified in 40 CFR 63.654 paragraphs (f)(1) through (f)(5) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(e) The Permittee of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6- month period when any of the compliance exceptions specified in 40 CFR 63.654 paragraphs (g)(1) through (g)(6) occur. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the compliance exceptions specified in 40 CFR 63.654 paragraphs (g)(1) through (g)(6) occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emissions averages, as provided in 40 CFR 63.654 paragraph (g)(8). A Permittee may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph if the reports contain the information required by paragraphs (g)(1) through (g)(8) of 40 CFR 63.654.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in 40 CFR 63.654 paragraphs (g)(2) through (g)(5) except that information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source.

(2) A Permittee who elects to comply with 40 CFR 63.646 by using a fixed roof and an internal floating roof or by using an external floating roof converted to an internal floating roof shall submit the results of each inspection conducted in accordance with 40 CFR 63.120(a) of subpart G of this part in which a failure is detected in the control equipment.

(i) For vessels for which annual inspections are required under 40 CFR 63.120(a)(2)(i) or (a)(3)(ii) of Subpart G of this part, the specifications and requirements listed in 40 CFR 63.654 paragraphs (g)(2)(i)(A) through (g)(2)(i)(C) apply.

(A) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

(B) Except as provided in 40 CFR 63.654 paragraph (g)(2)(i)(C), each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(C) If an extension is utilized in accordance with 40 CFR 63.120(a)(4) of Subpart G of this part, the Permittee shall, in the next Periodic Report, identify the vessel; include the documentation specified in 40 CFR 63.120(a)(4) of Subpart G of this part; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(ii) For vessels for which inspections are required under 40 CFR 63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of Subpart G of this part (i.e., internal inspections), the specifications and requirements listed in 40 CFR 63.654 paragraphs (g)(2)(ii)(A) and (g)(2)(ii)(B) apply.

(A) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(3) A Permittee who elects to comply with 40 CFR 63.646 by using an external floating roof shall meet the periodic reporting requirements specified in 40 CFR 63.654 paragraphs (g)(3)(i) through (g)(3)(iii).

(i) The Permittee shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with 40 CFR 63.120(b) of Subpart G of this part in which the seal and seal gap requirements of 40 CFR 63.120(b)(3), (b)(4), (b)(5), or (b)(6) of Subpart G of this part are not met. This documentation shall include the information specified in 40 CFR 63.654 paragraphs (e)(3)(i)(A) through (e)(3)(i)(D).

(A) The date of the seal gap measurement.

(B) The raw data obtained in the seal gap measurement and the calculations described in 40 CFR 63.120(b)(3) and (b)(4) of Subpart G of this part.

(C) A description of any seal condition specified in 40 CFR 63.120(b)(5) or (b)(6) of Subpart G of this part that is not met.

(D) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(ii) If an extension is utilized in accordance with 40 CFR 63.120(b)(7)(ii) or (b)(8) of Subpart G of this part, the Permittee shall, in the next Periodic Report, identify the vessel; include the documentation specified in 40

CFR 63.120(b)(7)(ii) or (b)(8) of Subpart G of this part, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(iii) The Permittee shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by 40 CFR 63.120(b)(10) of Subpart G of this part. This documentation shall meet the specifications and requirements in 40 CFR 63.654 paragraphs (e)(3)(iii)(A) and (e)(3)(iii)(B).

(A) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(4) A Permittee who elects to comply with 40 CFR 63.646 by using an external floating roof converted to an internal floating roof shall comply with the periodic reporting requirements of paragraph (e)(2) of 40 CFR 63.654.

(5) A Permittee who elects to comply with 40 CFR 63.646 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in 40 CFR 63.654 paragraphs (g)(5)(i) through (g)(5)(iii).

(i) The Periodic Report shall include the information specified in 40 CFR 63.654 paragraphs (g)(5)(i)(A) and (g)(5)(i)(B) for those planned routine maintenance operations that would require the control device not to meet the requirements of 40 CFR 63.119(e)(1) or (e)(2) of Subpart G of this part, as applicable.

(A) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description shall include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(B) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description shall include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the requirements of 40 CFR 63.119 (e)(1) or (e)(2) of Subpart G of this part, as applicable, due to planned routine maintenance.

(ii) If a control device other than a flare is used, the Periodic Report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance Status report. The description shall include: Identification of the control device for which the measured parameters were outside of the established ranges, and causes for the measured parameters to be outside of the established ranges.

(iii) If a flare is used, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in 40 CFR 63.11(b) of Subpart A of this part and shall include:

Identification of the flare that does not meet the general requirements specified in 40 CFR 63.11(b) of Subpart A of this part, and reasons the flare did not meet the general requirements specified in 40 CFR 63.11(b) of Subpart A of this part.

(6) For miscellaneous process vents for which continuous parameter monitors are required by this subpart, periods of excess emissions shall be identified in the Periodic Reports and shall be used to determine compliance with the emission standards.

(i) Period of excess emission means any of the following conditions:

(A) An operating day when the daily average value of a monitored parameter, except presence of a flare pilot flame, is outside the range specified in the Notification of Compliance Status report. Monitoring data recorded during periods of monitoring system breakdown, repairs, calibration checks and zero (low-level) and high-level adjustments shall not be used in computing daily average values of monitored parameters.

(B) An operating day when all pilot flames of a flare are absent.

(C) An operating day when monitoring data required to be recorded in paragraphs (g)(3) (i) and (ii) of this section are available for less than 75 percent of the operating hours.

(D) For data compression systems approved under paragraph (f)(5)(iii) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

(ii) For miscellaneous process vents, excess emissions shall be reported for the operating parameters specified in table 10 of this subpart unless other site-specific parameter(s) have been approved by the operating permit authority.

(iii) Periods of startup and shutdown that meet the definition of 40 CFR 63.641, and malfunction that meet the definition in 40 CFR 63.2 and periods of performance testing and monitoring system calibration shall not be considered periods of excess emissions. Malfunctions may include process unit, control device, or monitoring system malfunctions.

(7) If a performance test for determination of compliance for a new emission point subject to this subpart or for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic Report, the results of the performance test shall be included in the Periodic Report.

(i) Results of the performance test shall include the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) and the values of the monitored operating parameters.

(ii) The complete test report shall be maintained onsite.

(8) The Permittee of a source shall submit quarterly reports for all emission points included in an emissions average.

(i) The quarterly reports shall be submitted no later than 60 calendar days after the end of each quarter. The first report shall be submitted with the Notification of Compliance Status report no later than 150 days after the compliance date specified in 40 CFR 63.640.

(ii) The quarterly reports shall include:

(A) The information specified in this paragraph and in 40 CFR 63.654 paragraphs (g)(2) through (g)(7) for all storage vessels included in an emissions average;

(B) The information required to be reported by 40 CFR 63.428 (h)(1), (h)(2), and (h)(3) for each gasoline loading rack included in an emissions average, unless this information has already been submitted in a separate report;

(C) Any information pertaining to each wastewater stream included in an emissions average that the source is required to report under the Implementation Plan for the source;

(D) The credits and debits calculated each month during the quarter;

(E) A demonstration that debits calculated for the quarter are not more than 1.30 times the credits calculated for the quarter, as required under 40 CFR 63.652(e)(4);

(F) The values of any inputs to the credit and debit equations in 40 CFR 63.652 (g) and (h) that change from month to month during the quarter or that have changed since the previous quarter; and

(G) Any other information the source is required to report under the Implementation Plan for the source.

(f) Other reports shall be submitted as specified in Subpart A of this part and as follows:

(1) Reports of startup, shutdown, and malfunction required by 40 CFR 63.10(d)(5). Records and reports of startup, shutdown, and malfunction are not required if they pertain solely to Group 2 emission points, as defined in 40 CFR 63.641, that are not included in an emissions average. For purposes of this paragraph, startup and shutdown shall have the meaning defined in 40 CFR 63.641, and malfunction shall have the meaning defined in 40 CFR 63.2; and

(2) For storage vessels, notifications of inspections as specified in 40 CFR 63.654 paragraphs (h)(2)(i) and (h)(2)(ii);

(i) In order to afford the Administrator the opportunity to have an observer present, the Permittee shall notify the Administrator of the refilling of each Group 1 storage vessel that has been emptied and degassed.

(A) Except as provided in 40 CFR 63.654 paragraphs (h)(2)(i) (B) and (C), the Permittee shall notify the Administrator in writing at least 30 calendar days prior to filling or refilling of each storage vessel with organic HAP's to afford the Administrator the opportunity to inspect the storage vessel prior to refilling.

(B) Except as provided in 40 CFR 63.654 paragraph (h)(2)(i)(C), if the internal inspection required by 40 CFR 63.120(a)(2), 63.120(a)(3), or 63.120(b)(10) of Subpart G of this part is not planned and the Permittee could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP's, the Permittee shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. This notification, including the written documentation, may also be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

(C) The State or local permitting authority can waive the notification requirements of paragraphs (h)(2)(i)(A) and/or (h)(2)(i)(B) of 40 CFR 63.654 for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notification required by paragraph (h)(2)(i)(A) of 40 CFR 63.654, or sooner than 7 days after submitting the notification required by paragraph (h)(2)(i)(B) of 40 CFR 63.654 for all storage vessels, or for individual storage vessels on a case-by-case basis.

(ii) In order to afford the Administrator the opportunity to have an observer present, the Permittee of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by 40 CFR 63.120 (b)(1) or (b)(2) of Subpart G of this part. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

(3) For owners or operators of sources required to request approval for a nominal control efficiency for use in calculating credits for an emissions average, the information specified in 40 CFR 63.652(h).

(4) A Permittee may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in 40 CFR 63.654 paragraph (i).

(i) Requests shall be submitted with the Application for Approval of Construction or Reconstruction for new sources and no later than 18 months prior to the compliance date for existing sources. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal. Requests shall contain the information specified in 40 CFR 63.654 paragraphs (h)(5)(iii) through (h)(5)(iv), as applicable.

(ii) The provisions in 40 CFR 63.8(f)(5)(i) of Subpart A of this part shall govern the review and approval of requests.

(iii) A Permittee may request approval to use an automated data compression recording system that does not record monitored operating parameter values at a set frequency (for example, once every hour) but records all values that meet set criteria for variation from previously recorded values.

(A) The requested system shall be designed to:

(1) Measure the operating parameter value at least once every hour.

(2) Record at least 24 values each day during periods of operation.

(3) Record the date and time when monitors are turned off or on.

(4) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

(5) Compute daily average values of the monitored operating parameter based on recorded data.

(B) The request shall contain a description of the monitoring system and data compression recording system including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all criteria of paragraph (h)(5)(iii)(A) of 40 CFR 63.654.

(iv) A Permittee may request approval to use other alternative monitoring systems according to the procedures specified in 40 CFR 63.8(f) of Subpart A of this part.

(5) The Permittee shall submit the information specified in 40 CFR 63.654 paragraphs (h)(6)(i) through (h)(6)(iii), as applicable. For existing sources, this information shall be submitted in the initial Notification of Compliance Status report. For a new source, the information shall be submitted with the application for approval of construction or reconstruction required by 40 CFR 63.5(d) of Subpart A of this part. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units.

(ii) The determination of applicability of this subpart to any storage vessel for which use varies from year to year.

(iii) The determination of applicability of this subpart to any distillation unit for which use varies from year to year.

(g) Recordkeeping.

(1) The Permittee subject to the storage vessel provisions in 40 CFR 63.646 shall keep the records specified in 40 CFR 63.123 of Subpart G of this part except as specified in 40 CFR 63.654 paragraphs (i)(1)(i) through (i)(1)(iv).

(i) Records related to gaskets, slotted membranes, and sleeve seals are not required for storage vessels within existing sources.

(ii) All references to 40 CFR 63.122 in 40 CFR 63.123 of Subpart G of this part shall be replaced with 40 CFR 63.654(e).

(iii) All references to 40 CFR 63.150 in 40 CFR 63.123 of Subpart G of this part shall be replaced with 40 CFR 63.652.

(iv) If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

(2) Each Permittee required to report the results of performance tests under 40 CFR 63.654 paragraphs (f) and (g)(7) shall retain a record of all reported results as well as a complete test report, as described in 40 CFR 63.654 paragraph (f)(2)(ii) for each emission point tested.

(3) All other information required to be reported under 40 CFR 63.654 paragraphs (a) through (h) shall be retained for 5 years.

(h) To document compliance with Condition D.4.20, if the Permittee uses emissions averaging, the permittee shall keep records of all the required parameters listed in Condition D.4.20.

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

D.4.23 Recordkeeping Requirements [40CFR 60.696] [326 IAC 12]

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

(a) Each Permittee of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

(b) (1) For individual drain systems subject to Sec. 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

(2) For junction boxes subject to Sec. 60.692-2, the location, date, and corrective action shall be recorded for inspections required by Sec. 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(3) For sewer lines subject to Sec. Sec. 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by Sec. Sec. 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

(c) For oil-water separators subject to Sec. 60.692-3, the location, date, and corrective action shall be recorded for inspections required by by Sec. 60.692-3(a) when a problem is identified that could result in VOC emissions.

(d) For closed vent systems subject to Sec. 60.692-5 and completely closed drain systems subject to Sec. 60.693-1, the location, date, and corrective action shall be recorded for inspections required by Sec. 60.692-5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

(e) (1) If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.
(2) The reason for the delay as specified in Sec. 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.
(3) The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.
(4) The date of successful repair or corrective action shall be recorded.

(f) (1) A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.
(2) The following information pertaining to the design specifications shall be kept.
(i) Detailed schematics, and piping and instrumentation diagrams.
(ii) The dates and descriptions of any changes in the design specifications.
(3) The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 oC (1,500 oF) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(iii) Periods when the closed vent systems and control devices required in Sec. 60.692 are not operated as designed, including periods when a flare pilot does not have a flame shall be recorded and kept for 2 years after the information is recorded.

(iv) Dates of startup and shutdown of the closed vent system and control devices required in Sec. 60.692 shall be recorded and kept for 2 years after the information is recorded.

(v) The dates of each measurement of detectable emissions required in Sec. Sec. 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.

(vi) The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.

(vii) The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.

(viii) Each Permittee of an affected facility that uses a thermal incinerator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 oC (50 oF) below the design combustion zone temperature, and shall keep such records for 2 years after the information is recorded.

(ix) Each Permittee of an affected facility that uses a catalytic incinerator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 oC (50 oF) below the design gas stream temperature, and records of all 3-hour periods during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference, and shall keep such records for 2 years after the information is recorded.

(x) Each Permittee of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(A) Each Permittee of an affected facility that uses a carbon adsorber which is regenerated directly onsite shall maintain continuous records of the volatile organic compound concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(B) If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

(g) If the Permittee elects to install a tightly sealed cap or plug over a drain that is out of active service, the owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which indicate the location of such drains.

(h) For stormwater sewer systems subject to the exclusion in Sec. 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

(i) For ancillary equipment subject to the exclusion in Sec. 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonsrate that the ancillary equipment does not come in contact with or store oily wastewater.

(j) For non-contact cooling water systems subject to the exclusion in Sec. 60.692-1(d)(3), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

(k) For oil-water separators subject to Sec. 60.693-2, the location, date, and corrective action shall be recorded for inspections required by Sec. Sec. 60.693-2(a)(1)(iii)(A) and (B), and shall be maintained for the time period specified in paragraphs (k)(1) and (2) of this section.

(1) For inspections required by Sec. 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.

(2) For inspections required by Sec. 60.693-2(a)(1)(iii)(B), two years after the information is recorded.

D.4.24 Reporting Requirements [40CFR 60.698] [326 IAC 12]

Pursuant to 40 CFR 60.698, the Permittee shall comply with the following requirements:

(a) The Permittee electing to comply with the provisions of Sec. 60.693 shall notify the Administrator of the alternative standard selected in the report required in Sec. 60.7.

(b) (1) Each Permittee of a facility subject to this subpart shall submit to the

Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

(2) Each Permittee of an affected facility that uses a flare shall submit to the Administrator within 60 days after initial startup, as required under Sec. 60.8(a), a report of the results of the performance test required in Sec. 60.696(c).

(c) A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to OAQ, IDEM.

(d) As applicable, a report shall be submitted semiannually to the Administrator that indicates:

(1) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal incinerator, as measured by the temperature monitoring device, is more than 28 [deg]C (50 [deg]F) below the design combustion zone temperature,

(2) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic incinerator, as measured by the temperature monitoring device, is more than 28 [deg]C (50 [deg]F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference, or,

(3) Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

(i) Each 3-hour period of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases from a carbon adsorber which is regenerated directly onsite is more than 20 percent greater than the design exhaust gas concentration level or reading.

(ii) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in Sec. 60.695(a)(3)(ii).

(e) If compliance with the provisions of this subpart is delayed pursuant to Sec. 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) one (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), constructed in 1945 and modified in 2006 and exhausting to stack 118;
(b) one (1) crude heater equipped with the Low-NOx burner, with a maximum heat input rate of 131 million British Thermal Units per hour (mmBtu/hr) of No. 6 residual oil and process gas, identified as C-II, exhausting to stack 1;
(c) one (1) unifiner heater, with a maximum heat input rate of 20 mmBtu/hr of process gas, identified as H-H5 and exhausting to stack 2;
(d) one (1) cycle oil heater, with a maximum heat input rate of 10 mmBtu/hr of process gas, identified as H-H2 and exhausting to stack 3;
(e) one (1) naphtha splitter heater, with a maximum heat input rate of 12.2 mmBtu/hr of process gas, identified as H-H3 and exhausting to stack 4;
(f) one (1) vacuum heater, with a maximum heat input rate of 14.1 mmBtu/hr of process gas, identified as V-IV and exhausting to stack 5;
(g) one (1) old Platformer heater, with a maximum heat input rate of 29 mmBtu/hr of process gas, identified as P-H1 and exhausting to stack 6;
(h) one (1) alkylation unit heater, with a maximum heat input rate of 13.2 mmBtu/hr of process gas, identified as A-H1 and exhausting to stack 7;
(i) one (1) auxiliary crude heater, with a maximum heat input rate of 10.1 mmBtu/hr of process gas, identified as C-I and exhausting to stack 11;
(j) one (1) platformer stabilizer reb, with a maximum heat input rate of 5.92 mmBtu/hr of process gas, identified as P-H2 and exhausting to stack 12;
(k) one (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;
(l) one (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;
(m) one (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;
(n) one (1) vacuum heater husky, with a maximum heat input rate of 6.27 mmBtu/hr of No. 6 residual oil and process gas, identified as VIII and exhausting to stack 64.
(o) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no sour water stripper overhead off-gas combustion), installed in 1945 and exhausting to stack 9.

(The information describing the process contained in this 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 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the emission units C-II, boilers Nos. 1, 2 and 3, V-IV, A-HI, H101, and V-III, when burning No. 6 residual fuel oil, shall not exceed 1.6 pounds per MMBtu heat input. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a thirty (30) day rolling weighted average.

D.5.3 No. 6 Fuel Usage [326 IAC 2-2]

The input of No. 6 fuel oil to the 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.5.4 General Provisions Relating to NESHAP [326 IAC 20-1][40 CFR Part 63, Subpart A]

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

D.5.5 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]

(a) The affected sources are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters, (40 CFR 63, Subpart DDDDD), as of the effective date of 40 CFR 63, Subpart DDDDD. Pursuant to this rule, the Permittee must comply with 40 CFR 63, Subpart DDDDD on and after three years after September 13, 2004, the effective date of 40 CFR 63, Subpart DDDDD.

(b) The following emissions units comprise the affected source for the large liquid fuel subcategory:
    (1) One (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8.

(2) One (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13.

(3) One (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14.

(c) The definitions of 40 CFR 63, Subpart DDDDD at 40 CFR 63.7575 are applicable to the affected source(s).

Compliance Determination Requirements

D.5.6 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition D.5.2 shall be determined utilizing one of the following options:

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed 1.6 pound per million Btu heat input by:

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

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

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

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

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

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

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

D.5.7 Visible Emissions Notations

(a) Visible emission notations of the boiler stacks (B1, B2 and B3) exhaust shall be performed once per 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.5.8 Record Keeping Requirements

(a) To document compliance with Conditions D.5.2, the Permittee shall maintain records in accordance with (1) through (6) below.

(1) Calendar dates covered in the compliance determination period;
(2) Actual No. 6 residual fuel oil usage per month since last compliance determination period and equivalent SO_2 emissions;
(3) A certification, signed by the Permittee, that the records of the fuel supplier certifications represent all of the fuel combusted during the period; and

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications.
(5) The name of the fuel supplier; and
(6) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document compliance with Condition D.5.4, the Permittee shall maintain records of visible emission notations of the three boiler stacks (B1, B2 and B3) once per shift.

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

D.5.9 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters - Notification Requirements [40 CFR 63, Subpart DDDDD]

(a) Pursuant to 40 CFR 63.7545(a) and 40 CFR 63.7506(b), the Permittee shall submit an Initial Notification containing the information specified in 40 CFR 63.9(b)(2) not later than 120 days after the effective date of 40 CFR 63, Subpart DDDDD as required by 40 CFR 63.7545(b).

(b) The notification required by paragraph (a) shall be submitted to:

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

and

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

The notification requires the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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)]:

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 Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (40 CFR 63, Subpart DDDDD), the boiler B4, is considered an existing affected source. The boiler is categorized under the large liquid fuel subcategory.

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

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

E.1.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.7565, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 for the boiler, B4, as specified in Table 10 of 40 CFR 63, Subpart DDDDD in accordance with schedule in 40 CFR 63 Subpart DDDDD.

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

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

E.1.2 Applicability of Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP Requirements [40 CFR Part 63, Subpart DDDDD]

The provisions of 40 CFR Part 63, Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) apply to the affected source. A copy of this rule is available on the US EPA Air Toxics Website at www.epa.gov/ttn/atw/boiler/boilerpg.html.

E.1.3 Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP Requirements [40 CFR Part 63, Subpart DDDDD]

Pursuant to CFR Part 63, Subpart DDDDD, the Permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters for the boiler, B4, as specified as follows on and after the initial compliance date, September 13, 2007.

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491.

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in §63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or constructed boiler or process heater, you must comply with the subpart no later by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

Sec. 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in Sec. 63.7575.

Sec. 63.7500 What emission limits, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under Sec. 63.7507.

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

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

Sec. 63.7505 What are my general requirements for complying with this subpart?

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

(c) You 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, you must demonstrate compliance using performance testing.

(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).
(1) For each continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a sitespecific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this sitespecific monitoring plan at least 60 days before your initial performance evaluation of your 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 your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.
(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (c)(3), and c)(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) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.
4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

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

Sec. 63.7510 What are my initial compliance requirements and by what date must I conduct them?

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

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

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

(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

Sec. 63.7515 When must I conduct subsequent performance tests or fuel analyses?

(a) You must conduct all applicable performance tests according to Sec. 63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

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

(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you 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, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

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

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

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

(f) You must conduct three separate test runs for each performance test required in this section, as specified in Sec. 63.7(e)(3). Each test run must last at least 1 hour.

(g) To determine compliance with the emission limits, you 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.

Sec. 63.7521 What fuel analyses and procedures must I use?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.

(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) Transfer all samples to a clean plastic bag for further processing.

(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) Throughly mix and pour the entire composite sample over a clean plastic sheet.

(2) Break sample pieces larger than 3 inches into smaller sizes.

(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) Separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) Grind the sample in a mill.

(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

Sec. 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

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

(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in Sec. 63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to Sec. 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input (Cinput) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 5 of this section.

$$Cl_{input} = \sum_{i=1}^{n} \left[(C_i)(Q_i) \right] \qquad \text{(Eq. 5)}$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ``1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in Sec. 63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in Sec. 63.7575, as your operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in Sec. 63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in Sec. 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to Sec. 63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.

$$P_{90} = \text{mean} + (SD \times t) \qquad \text{(Eq. 8)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n}\left[(C_{i90})(Q_i)(1.028)\right] \qquad \text{(Eq. 9)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ``1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

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

Sec. 63.7545 What notifications must I submit and when?

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

(c) As specified in Sec. 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in Sec. 63.7530(a), you must submit a Notification of Compliance Status according to Sec. 63.9(h)(2)(ii). For each initial compliance demonstration, you 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 Sec. 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.

(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.

(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

Sec. 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under Sec. 63.10(a), you 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 this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in Sec. 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 your source in Sec. 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 your source in Sec. 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), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.

(1) Company name and address.

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

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

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of Sec. 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of Sec. 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of Sec. 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of Sec. 63.7530, the maximum TSM input operating limit using Equation 6 of Sec. 63.7530, or the maximum mercury input operating limit using Equation 7 of Sec. 63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.

(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in Sec. 63.10(d)(5)(i).

(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(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 you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. 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 you 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.

(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 you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you 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 Sec. 63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

Sec. 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

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

(2) The records in Sec. 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 Sec. 63.10(b)(2)(viii).

(c) You 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 you.

(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of Sec. 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 9 of Sec. 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. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of Sec. 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 11 of Sec. 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. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If your 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, you must keep the records in paragraphs (e)(1) and (2) of this section.

(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.

Sec. 63.7560 In what form and how long must I keep my records?

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

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

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

Sec. 63.7565 What parts of the General Provisions apply to me?

Appendix B to this subpart shows which parts of the General Provisions in Sec. Sec. 63.1 through 63.15 apply to you.

Sec. 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in Sec. 63.7500(a) and (b) under Sec. 63.6(g).

(2) Approval of alternative opacity emission limits in Sec. 63.7500(a) under Sec. 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under Sec. 63.7(e)(2)(ii) and (f) and as defined in Sec. 63.90.

(4) Approval of major change to monitoring under Sec. 63.8(f) and as defined in Sec. 63.90.

(5) Approval of major change to recordkeeping and reporting under Sec. 63.10(f) and as defined in Sec. 63.90.

Sec. 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in Sec. 63.2 (the General Provisions), and in this section as follows:

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Bag leak detection system means an instrument that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biomass fuel means unadulterated wood as defined in this subpart, wood residue, and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388-991 .\1\, ``Standard Specification for Classification of Coals by Rank \1\'' (incorporated by reference, see Sec. 63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.

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 (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.

Construction/demolition material means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.
Deviation. (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1'' (incorporated by reference, see Sec. 63.14(b)).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.

Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Electrostatic precipitator means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles collecting surface, and transporting the particles into a hopper.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.

Federally enforceable means all limitations and conditions that are enforceable by the EPA 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.

Firetube boiler means a boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210[deg]F (99[deg]C).

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Large gaseous fuel subcategory includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.

Large liquid fuel subcategory includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Large solid fuel subcategory includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.

Limited use gaseous fuel subcategory includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Limited use liquid fuel subcategory includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Limited use solid fuel subcategory includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Liquid fossil fuel means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.

Minimum pressure drop means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means 90 percent of the lowest test-run average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber flow rate means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent flow rate means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum voltage or amperage means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

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) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-03a, ``Standard Specification for Liquid Petroleum Gases'' (incorporated by reference, see Sec. 63.14(b)).

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

Process heater means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1'' (incorporated by reference, see Sec. 63.14(b)).

Responsible official means responsible official as defined in 40 CFR 70.2.

Small gaseous fuel subcategory includes any firetube boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and any boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

Small liquid fuel subcategory includes any firetube boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and any boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Small solid fuel subcategory includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

Solid fuel includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

Total selected metals means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Unadulterated wood means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

Watertube boiler means a boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes.
Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

Tables to Subpart DDDDD of Part 63

TABLE 1 TO SUBPART DDDDD OF PART 63.—EMISSION LIMITS AND WORK PRACTICE STANDARDS

As stated in § 63.7500, you must comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
4. New or reconstructed large liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0005 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).

TABLE 2 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITHPARTICULATE MATTER EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	You must meet these operating limits
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
2. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
4. Any other control type	This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

TABLE 4 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH HYDROGEN CHLORIDE EMISSION LIMITS

As stated in § 63.7500, you must comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet scrubber control	Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
2. Dry scrubber control	Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
3. Fuel analysis	Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to § 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.

TABLE 5 TO SUBPART DDDDD OF PART 63.—PERFORMANCE TESTING REQUIREMENTS

As stated in § 63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	**a. Select sampling ports location and the number of traverse points.**	**Method 1 in appendix A to part 60 of this chapter.**
	b. Determine velocity and volumetric flow-rate of the stack gas.	**Method 2, 2F, or 2G in appendix A to part 60 of this chapter.**
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	**Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).**
	d. Measure the moisture content of the stack gas.	**Method 4 in appendix A to part 60 of this chapter.**
	e. Measure the particulate matter emission concentration.	**Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.**
	f. Convert emissions concentration to lb per MMBtu emission rates.	**Method 19 F-factor methodology in appendix A to part 60 of this chapter.**
3. Hydrogen chloride	**a. Select sampling ports location and the number of traverse points.**	**Method 1 in appendix A to part 60 of this chapter.**
	b. Determine velocity and volumetric flow-rate of the stack gas.	**Method 2, 2F, or 2G in appendix A to part 60 of this chapter.**
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	**Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).**
	d. Measure the moisture content of the stack gas.	**Method 4 in appendix A to part 60 of this chapter.**
	e. Measure the particulate matter emission concentration.	**Method 26 or 26A in appendix A to part 60 of this chapter.**
	f. Convert emissions concentration to lb per MMBtu emission rates.	**Method 19 F-factor methodology in appendix A to part 60 of this chapter.**
5. Carbon Monoxide	**a. Select the sampling ports location and the number of traverse points.**	**Method 1 in appendix A to part 60 of this chapter.**
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	**Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).**

	c. Measure the moisture content of the stack gas.	**Method 4 in appendix A to part 60 of this chapter.**
	d. Measure the carbon monoxide emission concentration.	**Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)) when the fuel is natural gas.**

TABLE 6 TO SUBPART DDDDD OF PART 63.—FUEL ANALYSIS REQUIREMENTS

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources:

To conduct a fuel analysis for the following pollutant	You must	Using
3. Hydrogen chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	SW–846–9250 or ASTM E776–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

TABLE 7 TO SUBPART DDDDD OF PART 63.—ESTABLISHING OPERATING LIMITS

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	**And your operating limits are based on**	**You must**	**Using**	**According to the following requirements**
1. Particulate matter, mercury, or total selected metals.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect pressure drop and liquid flowrate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control).	i. Establish a site-specific minimum voltage and secondary current or total power input according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(c).	(1) Data from the sorbent injection rate monitors and hydrogen chloride performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

TABLE 9 TO SUBPART DDDDD OF PART 63.—REPORTING REQUIREMENTS

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance report	a. Information required in § 63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i)	Semiannually according to the requirements in § 63.7550(b).
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in § 63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.1	**Applicability**	**Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications.**	**Yes.**
§63.2	**Definitions**	**Definitions for part 63 standards.**	**Yes.**
§63.3	**Units and Abbreviations**	**Units and abbreviations for part 63 standards.**	**Yes.**
§63.4	**Prohibited Activities**	**Prohibited Activities; Compliance date; Circumvention, Severability.**	**Yes.**

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.5	Construction/Reconstruction.	Applicability; applications; approvals.	Yes.
§63.6(a)	Applicability	GP apply unless compliance extension; and GP apply to area sources that become major.	Yes.
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed sources.	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f).	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal.	Yes.
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major.	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source.	Yes.
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources.	Comply according to date in subpart, which must be no later than 3 years after effective date; and for 112(f) standards, comply within 90 days of effective date unless compliance extension.	Yes.
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major.	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years).	Yes.
§63.6(d)	[Reserved]		
§63.6(e)(1)-(2)	Operation & Maintenance.	Operate to minimize emissions at all times; and Correct malfunctions as soon as practicable; and Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met.	Yes.
§63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP).	Requirement for SSM and startup, shutdown, malfunction plan; and content of SSMP.	Yes.
§63.6(f)(1)	Compliance Except During SSM.	Comply with emission standards at all times except during SSM.	Yes.
§63.6(f)(2)-(3)	Methods for Determining Compliance.	Compliance based on performance test, operation and maintenance plans, records, inspection.	Yes.
§63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard.	Yes.
§63.6(h)(1)	Compliance with Opacity/VE Standards.	Comply with opacity/VE emission limitations at all times except during SSM.	Yes.
§63.6(h)(2)(i)	Determining Compliance with Opacity/Visible Emission (VE) Standards.	If standard does not state test method, use Method 9 for opacity and Method 22 for VE.	No.
§63.6(h)(2)(ii)	[Reserved]		

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart.	Yes.
§63.6(h)(3)	[Reserved]		
§63.6(h)(4)	Notification of Opacity/VE Observation Date.	Notify Administrator of anticipated date of observation.	No.
§63.6(h)(5)(i),(iii)-(v)	Conducting Opacity/VE Observations.	Dates and Schedule for conducting opacity/VE observations.	No.
§63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times.	Must have at least 3 hours of observation with thirty, 6-minute averages.	No.
§63.6(h)(6)	Records of Conditions During Opacity/VE observations.	Keep records available and allow Administrator to inspect.	No.
§63.6(h)(7)(i)	Report continuous opacity monitoring system Monitoring Data from Performance Test.	Submit continuous opacity monitoring system data with other performance test data.	Yes.
§63.6(h)(7)(ii)	Using continuous opacity monitoring system instead of Method 9.	Can submit continuous opacity monitoring system data instead of Method 9 results even if subpart requires Method 9, but must notify Administrator before performance test.	No.
§63.6(h)(7)(iii)	Averaging time for continuous opacity monitoring system during performance test.	To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages.	Yes.
§63.6(h)(7)(iv)	Continuous opacity monitoring system requirements.	Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§63.8(e), continuous opacity monitoring systems are properly maintained and operated according to §63.8(c) and data quality as §63.8(d).	Yes.
§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards.	Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered.	Yes.
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance.	Yes.
§63.6(h)(9)	Adjusted Opacity Standard.	Procedures for Administrator to adjust an opacity standard.	Yes.
§63.6(i)(1)-(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§63.6(j)	Presidential Compliance Exemption.	President may exempt source category from requirement to comply with rule.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.7(a)(1)	Performance Test Dates.	Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations.	Yes.
§63.7(a)(2)	Performance Test Dates	New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance	Yes.
§63.7(a)(2)(ii-viii)	[Reserved]		
§63.7(a)(2)(ix)	Performance Test Dates	1. New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance; and. 2. If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard.	Yes. No.
§63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA Section 114 at any time.	Yes.
§63.7(b)(1)	Notification of Performance Test.	Must notify Administrator 60 days before the test.	No.
§63.7(b)(2)	Notification of Rescheduling.	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date.	Yes.
§63.7(c)	Quality Assurance/Test Plan.	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: test plan approval procedures; and performance audit requirements; and internal and external QA procedures for testing.	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities.	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests.	1. Performance tests must be conducted under representative conditions; and 2. Cannot conduct performance tests during SSM; and 3. Not a deviation to exceed standard during SSM; and 4. Upon request of Administrator, make available records necessary to determine conditions of performance tests.	No. Yes. Yes. Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests.	Must conduct according to rule and EPA test methods unless Administrator approves alternative.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.7(e)(3)	Test Run Duration	Must have three separate test runs; and Compliance is based on arithmetic mean of three runs; and conditions when data from an additional test run can be used.	Yes.
§63.7(e)(4)	Interaction with other sections of the Act.	Nothing in §63.7(e)(1) through (4) can abrogate the Administrator's authority to require testing under Section 114 of the Act.	Yes.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method.	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; and must submit performance test data 60 days after end of test with the Notification of Compliance Status; and keep data for 5 years.	Yes.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test.	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements.	Subject to all monitoring requirements in standard.	Yes.
§63.8(a)(2)	Performance Specifications.	Performance Specifications in appendix B of part 60 apply.	Yes.
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in §63.11 apply.	No.
§63.8(b)(1)(i)-(ii)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§63.8(b)(1)(iii)	Monitoring	Flares not subject to this section unless otherwise specified in relevant standard.	No.
§63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems.	Specific requirements for installing monitoring systems; and must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise; and if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup.	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance.	Maintain monitoring system in a manner consistent with good air pollution control practices.	Yes.
§63.8(c)(1)(i)	Routine and Predictable SSM.	Maintain and operate CMS according to §63.6(e)(1).	Yes.
§63.8(c)(1)(ii)	SSM not in SSMP	Must keep necessary parts available for routine repairs of CMSs.	Yes.
§63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	Must develop and implement an SSMP for CMSs.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.8(c)(2)-(3)	Monitoring System Installation.	Must install to get representative emission and parameter measurements; and must verify operational status before or at performance test.	Yes.
§63.8(c)(4)	Continuous Monitoring System (CMS) Requirements.	CMSs must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts.	No.
§63.8(c)(4)(i)	Continuous Monitoring System (CMS) Requirements.	Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period.	Yes.
§63.8(c)(4)(ii)	Continuous Monitoring System (CMS) Requirements.	Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period.	No.
§63.8(c)(5)	Continuous Opacity Monitoring system (COMS) Requirements.	Must do daily zero and high level calibrations.	Yes.
§63.8(c)(6)	Continuous Monitoring System (CMS) Requirements.	Must do daily zero and high level calibrations.	No.
§63.8(c)(7)-(8)	Continuous Monitoring Systems Requirements.	Out-of-control periods, including reporting.	Yes.
§63.8(d)	Continuous Monitoring Systems Quality Control.	Requirements for continuous monitoring systems quality control, including calibration, etc.; and must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions.	Yes.
§63.8(e)	Continuous monitoring systems Performance Evaluation.	Notification, performance evaluation test plan, reports.	Yes.
§63.8(f)(1)-(5)	Alternative Monitoring Method.	Procedures for Administrator to approve alternative monitoring.	Yes.
§63.8(f)(6)	Alternative to Relative Accuracy Test.	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system.	No.
§63.8(g)(1)-(4)	Data Reduction	Continuous opacity monitoring system 6-minute averages calculated over at least 36 evenly spaced data points; and continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points.	Yes.
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system.	No.
§63.9(a)	Notification Requirements.	Applicability and State Delegation.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.9(b)(1)-(5)	Initial Notifications.	Submit notification 120 days after effective date; and Notification of intent to construct/reconstruct; and Notification of commencement of construct/reconstruct; Notification of startup; and Contents of each.	Yes.
§63.9(c)	Request for Compliance Extension.	Can request if cannotcomply by date or if installed BACT/LAER.	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Source.	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date.	Yes.
§63.9(e)	Notification of Performance Test.	Notify Administrator 60 days prior.	No.
§63.9(f)	Notification of VE/Opacity Test.	Notify Administrator 30 days prior.	No.
§63.9(g)	Additional Notifications When Using Continuous Monitoring Systems.	Notification of performance evaluation; and notification using continuous opacity monitoring system data; and notification that exceeded criterion for relative accuracy.	Yes.
§63.9(h)(1)-(6)	Notification of Compliance Status.	Contents; and due 60 days after end of performance test or other compliance demonstration, and when to submit to Federal vs. State authority.	Yes.
§63.9(i)	Adjustment of Submittal Deadlines.	Procedures for Administrator to approve change in when notifications must be submitted.	Yes.
§63.9(j)	Change in Previous Information.	Must submit within 15 days after the change.	Yes.
§63.10(a)	Recordkeeping/Reporting.	Applies to all, unless compliance extension; and when to submit to Federal vs. State authority; and procedures for owners of more than 1 source.	Yes.
§63.10(b)(1)	Recordkeeping/Reporting.	General Requirements; and keep all records readily available and keep for 5 years.	Yes.
§63.10(b)(2)(i)-(v)	Records related to Startup, Shutdown, and Malfunction.	Occurrence of each of operation (process, equipment); and occurrence of each malfunction of air pollution equipment; and maintenance of air pollution control equipment; and actions during startup, shutdown, and malfunction.	Yes.
§63.10(b)(2)(vi) and (x-xi)	Continuous monitoring systems Records.	Malfunctions, inoperative, out-of-control; and calibration checks; and adjustments, maintenance.	Yes.
§63.10(b)(2)(vii)-(ix)	Records.	Measurements to demonstrate compliance with emission limitations; and performance test, performance evaluation, and visible emission observation results; and measurements to determine conditions of performance tests and performance evaluations.	Yes.
§63.10(b)(2)(xii)	Records	Records when under waiver.	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test.	No.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status.	Yes.
§63.10(b)(3)	Records	Applicability Determinations.	Yes.
§63.10(c)(1),(5)-(8),(10)-(15).	Records	Additional Records for continuous monitoring systems.	Yes.
§63.10(c)(7)-(8)	Records	Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems.	No.
§63.10(d)(1)	General Reporting Requirements.	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results.	When to submit to Federal or State authority.	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations.	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§63.10(d)(5)	Startup, Shutdown, and Malfunction Reports.	Contents and submission	Yes.
§63.10(e)(1)(2)	Additional continuous monitoring systems Reports.	Must report results for each CEM on a unit; and written copy of performance evaluation; and 3 copies of continuous opacity monitoring system performance evaluation.	Yes.
§63.10(e)(3)	Reports	Excess Emission Reports	No.
§63.10(e)(3)(i-iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations).	No.
§63.10(e)(3)(iv-v)	Excess Emissions Reports.	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations); and provision to request semiannual reporting after compliance for one year; and submit report by 30th day following end of quarter or calendar half; and if there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations.	No.
§63.10(e)(3)(iv-v)	Excess Emissions Reports.	Must submit report containing all of the information in §63.10(c)(5-13), §63.8(c)(7-8).	No.
§63.10(e)(3)(vi-viii)	Excess Emissions Report and Summary Report.	Requirements for reporting excess emissions for continuous monitoring systems (now called deviations); Requires all of the information in §63.10(c)(5-13), §63.8(c)(7-8).	No.
§63.10(e)(4)	Reporting continuous opacity monitoring system data.	Must submit continuous opacity monitoring system data with performance test data.	Yes.
§63.10(f)	Waiver for Recordkeeping/Reporting.	Procedures for Administrator to waive.	Yes.
§63.11	Flares	Requirements for flares	No.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.12	**Delegation**	**State authority to enforce standards.**	**Yes.**
§63.13	**Addresses**	**Addresses where reports, notifications, and requests are sent.**	**Yes.**
§63.14	**Incorporation by Reference**	**Test methods incorporated by reference.**	**Yes.**
§63.15	**Availability of Information.**	**Public and confidential Information.**	**Yes.**

E.1.4 One Time Deadlines Relating to Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]

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

Requirement	Rule Cite	Affected Facility	Deadline
Initial Notification	40 CFR 63.7545(b) and 40 CFR 63.9(b)	B4	Submit initial notification not later than 15 days after the actual date of startup of the affected source.

SECTION E.2 FACILITY OPERATION CONDITIONS

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

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

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the 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.2.2 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.2.3 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.2.4 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 (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 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 fule 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.2.5 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.2.6 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition E.2.1 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.2.7 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.2.8 Record Keeping Requirements

(a) To document compliance with Conditions E.2.1and E.2.2, 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.2.7, 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.2.9 Reporting Requirements

A quarterly summary of the information to document compliance with Condition E.2.2 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.3 FACILITY OPERATION CONDITIONS

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

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.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 Kb.

E.3.2 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.4 FACILITY OPERATION CONDITIONS

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

(a) 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.4.1 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.4.2 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).

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 BRANCH
100 North Senate Avenue
Indianapolis, Indiana 46204
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 DATA SECTION

Part 70 Quarterly Report

Source Name:	Countrymark Cooperative, LLP
Source Address:	1200 Refinery Road, Mount Vernon, Indiana 47620
Mailing Address:	1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.:	T129-7882-00003
Facility:	Boilers B1, B2, 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 DATA SECTION

Part 70 Quarterly Report

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Mailing Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-7882-00003
Facility: 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 DATA SECTION

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

Addendum to the Technical Support Document (TSD) for a Significant Source Modification and Significant Permit Modification to a Part 70 Operating Permit

Source Background and Description

Source Name:	**Countrymark Cooperative, LLC**
Source Location:	**1200 Refinery Road, Mount Vernon, Indiana 4762**
County:	**Posey**
SIC Code:	**2911**
Operation Permit No.:	**T129-7882-00003**
Significant Source Modification No.:	**129-22917-00003**
Significant Permit Modification No.:	**129-23090-00003**
Permit Reviewer:	**Surya Ramaswamy / EVP**

On October 18, 2006, the Office of Air Quality (OAQ) had a notice published in the Mt. Vernon Democrat Newspaper, Mt. Vernon, Indiana, stating that Countrymark Cooperative, LLP had applied for a significant source modification and significant permit modification to make certain changes at their existing source. The notice also stated that OAQ proposed to issue a Part 70 Permit for this operation and provided information on how the public could review the proposed Part 70 Permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this Part 70 Permit should be issued as proposed.

On November 15, 2006, Ethan Chatfield, U.S. Environmental Protection Agency Region V, submitted comments on the proposed Title V permit. The summary of the comments and corresponding responses is as follows (bolded language has been added and the language with a line through it has been deleted):

Comment 1

Condition D.5.3: The footnote B on page 7 of 123 of the TSD states that Boiler B4 will be subject to the fuel usage limit of 3,214.92 thousand gallons but this is not reflected in condition D.5.3.

Response 1

In the permit application, Countrymark Cooperative, LLC requested to have the same fuel oil limit applicable to the boiler B4 as for the other existing boilers (B1, B2, and B3). The reason for this was that the source wanted to add this new boiler B4 to supplement the existing three (3) boilers and confirmed that the installation of new boiler will not result in increased utilization. Therefore, the existing fuel oil usage limit of 3,214.92 thousand gallons is now applicable to all four (4) boilers. However, since boiler B4 has a potential to burn the entire fuel amount, a separate fuel oil usage limit of 730,000 gallons is established for boiler B4 to avoid the applicability of PSD requirements. Therefore, Boiler B4 is only allowed to burn 730,000 gallons of oil out of the 3,214.92 thousand gallon limit to all the four (4) boilers. Condition D.5.3 has been revised as follows:

D.5.3 No. 6 Fuel Usage [326 IAC 2-2]

The input of No. 6 fuel oil to the ~~three~~ **four(4)** boilers B1, B2, ~~and~~ 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.

Comment 2

Condition E.2.2: This condition limits #6 Fuel Oil consumption to 1,000,000 gallons/year which equates to about one fifth of the capacity of B4 and 39 tons of SO_2 per year, according to my calculations. If boiler B4 burns refinery gas the remaining four fifth of the year, would the source exceed the 40 tons per year threshold?

Response 2

It was understood that the Boiler B4 would exceed the 40 tons per year threshold if they burn refinery gas for the remaining four fifth of the year. Taking this into account the #6 fuel oil consumption is limited to 730,000 gallons per year and the revised emission calculation is attached to the addendum.

The Condition E.2.2 and Part 70 Quarterly Report have been revised as follow:

Condition E.2.2 has been revised to reduce the No. 6 fuel oil usage to 730,000 gallons after taking in to account that refinery fuel gas will be burned the entire twelve (12) consecutive month period as a worst case scenario. The potential SO_2 emissions will be limited to less than 40 tons per year if the boiler B4 burns refinery fuel gas the entire twelve (12) consecutive month period plus 730 thousand gallons of fuel oil in the same period.

E.2.2 PSD Minor Limit [326 IAC 2-2]

The input of No. 6 fuel oil to Boiler B4 shall be limited to less than ~~1,000 thousand~~ **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.**

Compliance with this limit makes 326 IAC 2-2 (Prevention of Significant Deterioration) not applicable.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Mailing Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-7882-00003
Facility: 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 ~~1,000 thousand~~ **730,000** gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

Comment 3

Page 3 of 123 of the TSD: The source has not formally submitted a determination request to IDEM or USEPA as to whether the replacement of the flare constitutes reconstruction in accordance with 40 CFR 60.15(d). EPA requests a copy of Countrymark's formal request and IDEM's corresponding analysis for our concurrence once completed.

Response 3

On November 30, 2006 and December 6, 2006, Countrymark Cooperative has submitted the Reconstruction Cost Analysis. This analysis has been forwarded to USEPA Region 5. See Appendix B of this document for the Reconstruction Cost Analysis. Based on the cost analysis submitted, the reconstruction cost is less than 50% of construction of a new unit. Therefore there are no changes to the draft permit due to this comment.

On November 17, 2006, Matthew L. Smorch, Refinery Manager, submitted comments on the proposed Significant Source Modification (129-22917-00003) and Significant Permit Modification (129-23090-00003). The summary of the comments and corresponding responses is as follows (bolded language has been added and the language with a line through it has been deleted):

Comment 4

The permit contains a condition for Boiler B4 that restricts oil combustion in the unit to no more than 1,000 thousand gallons per 12 consecutive month period (Condition E.2.2). This limit was created to avoid the applicability of Prevention of Significant Deterioration (PSD) rules to the unit. The Technical Support Document provides a table (on page 6 of 123) which shows 39.65 tons per year of potential SO_2 emissions from Boiler B4 (at the 1,000,000 gallons per year limit) and no increase or decrease for any other units.

It was Countrymark's intent with this application that Boiler B4 simply be rolled into the existing fuel oil limit for Boilers B1, B2, and B3. This limit was created as a part of Significant Permit Modification No. 129-20112-00003 to cap fuel oil combustion at a point so as to avoid PSD applicability. By simply adding Boiler B4 to the existing limit of 3,214.92 thousand gallons per twelve consecutive month period (contained in Condition D.5.3), there is no net change in SO_2 emissions from this change (since the previous limit was established for the purpose of avoiding PSD for SO_2 emissions). As a result, Countrymark believes that the 1,000,000 gallons limit for Boiler B4 is unnecessary.

In consideration of these facts, Countrymark requests that the proposed permit be modified as follows:

1. Boiler B4 should be added to the boiler fuel limit in Condition D.5.3; and
2. The fuel oil combustion limit contained in Condition E.2.2 should be removed.

Response 4

Boiler B4 has been added to the boiler fuel limit in Condition D.5.3 (see Response 1).

Although the Boiler B4 will be subject to the same fuel usage limit of 3,214.92 thousand gallons per 12-month rolling period established for Boilers B1, B2, and B3 in SSM 129-18672-00003, issued on February 1, 2005, it has the capability of burning entire fuel usage limit . Therefore, it is necessary to include a separate No. 6 fuel oil usage limit for Boiler B4 where the annual fuel usage is limited to 730,000 gallons (with maximum fuel oil sulfur content of 0.5% based on the Subpart Dc). This fuel usage limitation will limit all the criteria pollutant to less than the major PSD threshold level in this source modification.

Countrymark Cooperative, LLP
Mt. Vernon, Indiana
Source ID 129-00003
Flare Reconstruction Cost Analysis

Item	Quantity	unit	$/unit	Total Costs - New Flare $	Total Costs - Project Scope $
Piping (estimated TIC/unit)					
20" Piping	3	ft	260	NA	-
16" Piping	654	ft	201	NA	-
12" Piping	9	ft	156	NA	-
10" Piping	272	ft	124	NA	-
8" Piping	228	ft	116	NA	-
6" Piping	150	ft	78	NA	-
4" Piping	30	ft	48	NA	NA
2" Piping	745	ft	37	NA	NA
1" Piping	470	ft	35	NA	NA
Flare and Vessels (actual equipment bids)					
Flare Tip & Ignition system				34,100	34,100
Thermocouple system				5,600	5,600
Flare Stack				64,800	64,800
Vertical Knockout Drum				34,000	34,000
Horizontal Knockout Drum				42,700	42,700
Miscellaneuos Equipment (estimated TIC)					
Knock-out Pump				7,500	7,500
Electrical & Instrumentation				30,000	20,000
Insulation			40,000	40,000	10,000
Cathodic Protection	-		60,000	60,000	-
Structural and Foundation (estimated TIC)					
Structural steel supports				10,260	-
Foundations - Vert. KO	7	yd*3	2,173	15,211	-
- Horz. KO	3	yd*3	2,173	6,519	-
Flare Pit - retaining walls	71	yd*3	2,173	154,283	-
Tunnel 3x8x20ft approx	23	yd*3	2,173	49,979	-
3 ft Concrete pipe	130	ft	138	17,940	
Crane/Heavy Equipment				75,000	55,000
Sub-Total				647,892	273,700
Contingency			8.0%	51,831	21,896
Escalation (applied to non bid cost only)			5.0%	23,335	4,625
Engineering (new construction)			15.0%	97,184	-
Engineering (project scope)			5.0%	-	13,685
Total				**820,242**	**313,906**

Project cost as a % of total installed cost of new flare: **38.3%**

Countrymark Cooperative, LLP

29 November 2006

Mr. Surya Ramaswamy
c/o IDEM, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204

Re: SSM129-22917-00003
SPM129-23090-00003
Countrymark Cooperative, LLP
Mt. Vernon, Indiana
NSPS Reconstruction Cost Analysis

Certified Mail No: 7004 1350 0001 8184 3858

Dear Mr. Ramaswamy:

Countrymark Cooperative, LLP (Countrymark) has received your request for a more detailed cost analysis pursuant to §60.15(d) for the proposed replacement of certain components of the flare at its Mt. Vernon refinery. Countrymark has updated the cost analysis to be consistent with the guidelines provided. Attached is a summary of component costs for installation of a new flare and a comparison of the components that will be replaced as a part of this project. The total installed cost for replacement components is approximately 29.1% of the cost of a new installation. As a result, Countrymark concludes that this project does not trigger the definition of reconstruction as established under §60.15.

If you have questions regarding this information, please contact Marty Novak of Countrymark at (812) 833-3647 or Dave Jordan of ERM at (317) 706-2006.

Sincerely,

Matthew L. Smorch
Refinery Manager

Countrymark®
CO-OP
1200 Refinery Road • Mt. Vernon, Indiana 47620-9225
(Main Office) 812-838-4341 (Toll Free) 800-832-5490

cc: Marty Novak, Countrymark
Dave Jordan, ERM

Enclosure: Flare Reconstruction Cost Analysis

Countrymark Cooperative, LLP
Mt. Vernon, Indiana
Source ID 129-00003
Flare Reconstruction Cost Analysis

Item	Quantity	unit	$/unit	Total Costs - New Flare $	Total Costs - Project Scope $
Piping (estimated TIC/unit)					
20" Piping	3	ft	260	780	-
16" Piping	654	ft	201	131,248	-
12" Piping	9	ft	156	1,404	-
10" Piping	272	ft	124	33,750	-
8" Piping	228	ft	116	26,375	-
6" Piping	150	ft	78	11,652	-
4" Piping	30	ft	48	1,441	1,500
2" Piping	745	ft	37	27,491	12,500
1" Piping	470	ft	35	16,450	1,000
Flare and Vessels (actual equipment bids)					
Flare Tip & Ignition system				34,100	34,100
Thermocouple system				5,600	5,600
Flare Stack				64,800	64,800
Vertical Knockout Drum				34,000	34,000
Horizontal Knockout Drum				42,700	42,700
Miscellaneuos Equipment (estimated TIC)					
Knock-out Pump				7,500	7,500
Electrical & Instrumentation				30,000	20,000
Insulation			40,000	40,000	10,000
Cathodic Protection	-		60,000	60,000	-
Structural and Foundation (estimated TIC)					
Structural steel supports				10,260	-
Foundations - Vert. KO	7	yd*3	2,173	15,211	-
- Horz. KO	3	yd*3	2,173	6,519	-
Flare Pit - retaining walls	71	yd*3	2,173	154,283	-
Tunnel 3x8x20ft approx	23	yd*3	2,173	49,979	-
3 ft Concrete pipe	130	ft	138	17,940	
Crane/Heavy Equipment				75,000	55,000
Sub-Total				898,482	288,700
Contingency			8.0%	71,879	23,096
Escalation (applied to non bid cost only)			5.0%	35,042	5,325
Engineering (new construction)			15.0%	134,772	-
Engineering (project scope)			5.0%	-	14,435
Total				**1,140,174**	**331,556**

Project cost as a % of total installed cost of new flare: **29.1%**

Addendum to Appendix : Emission Calculations
Boiler Emission
Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Indiana 47620
Operating Permit No.: 129-22917-00003
Reviewer: Surya Ramaswamy/EVP
Date: 22-Nov-06

Maximum Steam Producing Rate	70,000	lb/hr
Maximum Water Feed Rate	70,000	lb/hr
Btu required to convert water to steam	970	Btu/lb steam
Boiler Efficiency	80.00%	%

Maximum Required Heat Input = $\frac{70000 \text{ lb}}{\text{hr}} \times \frac{970 \text{ Btu}}{\text{lb of steam}} \times \frac{1.0 \text{ lb steam input}}{0.8 \text{ lb steam output}}$

= 84875000 Btu/hr
= 84.875 mmBTU/hr

No.6 Fuel Oil:

No.6 Fuel oil is limited 3,214,290 gallons per twelve consecutive months and 0.5% Sulfur content based on NSPS (Subpart Dc).

Maximum Fuel Oil Flow = 730,000 Gallons/yr
= 84.20 Gallons/hr
= 0.084 1000 Gallons/hr

Natural Gas:

Heat Content = 1020 Btu/cu.ft
Fuel Feed Rate = 83210.78 cu.ft/hr
= 0.083 mmcu.ft/hr

Refinery Fuel Gas:

Heat Content = 1000 Btu/cu.ft
Fuel Feed Rate = 84875.00 cu.ft/hr
= 0.085 mmcu.ft/hr

No.6 Fuel Oil Combustion

Pollutant	Maximum rate, thousand gal/hr	Emission Factor, lb/1000gallons	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	0.084	9.6	0.8083	3.540	0	3.540
PM10	0.084	9.07	0.7637	3.345	0	3.345
SO_2	0.084	157 x %S	6.6096	28.950	0	28.950
NOx	0.084	55	4.6309	20.283	0	20.283
VOC	0.084	0.28	0.0236	0.103	0	0.103
CO	0.084	5	0.4210	1.844	0	1.844
Lead	0.084	0.0005	0.0000	0.000	0	0.000
Benzene	0.084	0.0021	0.0002	0.001	0	0.001
Formaldehyde	0.084	0.075	0.0063	0.028	0	0.028
Hexane	0.084	1.8	0.1516	0.664	0	0.664
Naphthalene	0.084	0.00061	0.0001	0.000	0	0.000
Toluene	0.084	0.0034	0.0003	0.001	0	0.001

Emission Factor Source - AP42 Section 1.3, 9/98

Refinery Fuel Gas Combustion

Sulfur Content of Boiler Refinery Fuel Gas - 0.03% (Subject to NSPS Subpart J limit of 0.01 gr/dscf)

Pollutant	Maximum rate, mmcf/hr	Emission Factor, lb/mmcf	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	0.085	7.6	0.6451	2.825	0	2.825
PM10	0.085	7.6	0.6451	2.825	0	2.825
SO_2	0.085	950 x %S	2.4189	10.595	0	10.595
NOx	0.085	50	4.2438	18.588	0	18.588
VOC	0.085	5.5	0.4668	2.045	0	2.045
CO	0.085	84	7.1295	31.227	0	31.227
Lead	0.085	0.0005	0.0000	0.000	0	0.000
Benzene	0.085	0.0021	0.0002	0.001	0	0.001
Formaldehyde	0.085	0.075	0.0064	0.028	0	0.028
Hexane	0.085	1.8	0.1528	0.669	0	0.669
Naphthalene	0.085	0.00061	0.0001	0.000	0	0.000
Toluene	0.085	0.0034	0.0003	0.001	0	0.001

Emission Factor Source - AP-42 Section 1.4-7 Natural Gas Combustion, except SO_2 EPA 450/4-90-003. Refinery fuel gas HAP emission factors

Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum rate, mmcf/hr	Emission Factor, lb/mmcf	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	0.083	7.6	0.6324	2.770	0	2.770
PM10	0.083	7.6	0.6324	2.770	0	2.770
SO_2	0.083	0.6	0.0499	0.219	0	0.219
NOx	0.083	50	4.1605	18.223	0	18.223
VOC	0.083	5.5	0.4577	2.005	0	2.005
CO	0.083	84	6.9897	30.615	0	30.615
Lead	0.083	0.0005	0.0000	0.000	0	0.000
Benzene	0.083	0.0021	0.0002	0.001	0	0.001
Formaldehyde	0.083	0.075	0.0062	0.027	0	0.027
Hexane	0.083	1.8	0.1498	0.656	0	0.656
Naphthalene	0.083	0.00061	0.0001	0.000	0	0.000
Toluene	0.083	0.0034	0.0003	0.001	0	0.001

Emission Factor Source - AP-42 Section 1.4-7 Natural Gas Combustion.

Worst Case Boiler Summary

Pollutant	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	3.5591	15.589	0	6.366
PM10	3.3626	14.728	0	6.170
SO_2	46.5646	203.953	0	39.545
NOx	20.3905	89.311	0	38.871
VOC	0.4668	2.045	0	2.148
CO	7.1295	31.227	0	33.071
Lead	0.0002	0.001	0	0.000
Benzene	0.0008	0.003	0	0.002
Formaldehyde	0.0278	0.122	0	0.056
Hexane	0.6673	2.923	0	1.333
Naphthalene	0.0002	0.001	0	0.000
Toluene	0.0013	0.006	0	0.003

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Significant Source Modification and Significant Permit Modification to a Part 70 Operating Permit

Source Description and Location

Source Name:	**Countrymark Cooperative, LLP**
Source Location:	**1200 Refinery Road, Mount Vernon, IN 47620**
County:	**Posey**
SIC Code:	**2911**
Operation Permit No.:	**T129-7882-00003**
Operation Permit Issuance Date:	**July 21, 2003**
Significant Source Modification No.:	**129-22917-00003**
Significant Permit Modification No.:	**129-23090-00003**
Permit Reviewer:	**Surya Ramaswamy/EVP**

The Office of Air Quality (OAQ) has reviewed a modification application from Countrymark Cooperative, LLP relating to the operation of a petroleum refinery.

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) First Minor Source Modification No.: 129-18135, issued on November 17, 2003;
(b) First Significant Permit Modification No.: 129-17940, issued on November 24, 2003;
(c) First Significant Source Modification No.: 129-18672, issued on February 1, 2005;
(d) Second Significant Permit Modification No.: 129-20112, issued on March 21, 2005;
(e) First Administrative Amendment No.: 129-20343, issued on March 30, 2005;
(f) Second Minor Source Modification No.: 129-21168, issued on June 1, 2005; and
(g) Third Significant Permit Modification No.: 129-21251, issued on August 15, 2005.

County Attainment Status

The source is located in Posey County.

Pollutant	Status
PM-10	Attainment
PM-2.5	Attainment
SO_2	Attainment
NO_2	Attainment
8-hour Ozone	Attainment
CO	Attainment
Lead	Attainment

(a) On August 7, 2006, a temporary emergency rule took effect revoking the one-hour ozone standard in Indiana. The Indiana Air Pollution Control Board has approved a permanent rule revision to incorporate this change into 326 IAC 1-4-1. A permanent revision to 326 IAC 1-4-1 will take effect prior to the expiration of the emergency rule.

(b) 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.

(c) Posey County has been classified as attainment for PM2.5. U.S. EPA has not yet established the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 for PM2.5 emissions. Therefore, until the U.S.EPA adopts specific provisions for PSD review for PM2.5 emissions, it has directed states to regulate PM10 emissions as a surrogate for PM2.5 emissions.

(d) Posey County has been classified as attainment or unclassifiable for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(e) Fugitive Emissions
Since this type of operation is in one of the twenty-eight (28) listed source categories under 326 IAC 2-2 or 326 IAC 2-3, fugitive emissions are counted toward the determination of PSD and Emission Offset applicability.

Source Status

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

Pollutant	Emissions (tons/year)
PM	303.36
PM10	138.44
SO_2	8,710.57
VOC	5,462.47
CO	10,359.57
NO_x	851.53

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1).

(b) These emissions are based upon the Title V permit (T129-7742-00037) issued on August 22, 2003.

The table below summarizes the potential to emit HAPs for the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

HAPs	Potential To Emit (tons/year)
Single HAP	> 10
Total HAPs	> 25

This existing source is a major source of HAPs, as defined in 40 CFR 63.41, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Actual Emissions

The following table shows the actual emissions from the source. This information reflects the 2003 OAQ emission data.

Pollutant	Actual Emissions (tons/year)
PM	44.0
PM10	44.0
SO_2	1,610.0
VOC	649.0
CO	7,804.0
NO_x	397.0
HAP	Not Reported

Description of Proposed Modification

On April 4, 2006, Countrymark Cooperative, LLP submitted an application to the OAQ requesting to add one (1) new boiler, replace the refinery flare with a similar kind, add four (4) new storage tanks and to change service for the three (3) existing storage tanks. Countrymark Cooperative, LLP was issued a Part 70 Permit No. T129-7882-00003 on July 21, 2003.

The following is a list of the proposed emission units and pollution control devices:

(a) One (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 MMBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 MMBtu/hr), constructed in 1945 and modified in 2006 and exhausting to stack 18;

Note: The old main refinery flare structure, installed in 1945, is at the end of its recommended service life. It is Countrymark's intent to make a "replacement in kind" and this replacement will not affect the operating capacity of any other units at the refinery. The new flare structure will have the same operating parameters and will be the same diameter, but 25 feet higher. Countrymark also estimates that the capital cost to replace the flare is $515,204. The cost of components which will be replaced as apart of this modification (flare, HKO Drum, and VKO Drum) is $181,200, which is 35.2% of the cost of a replacement unit. Based on these information received by source the costs of the new Main Refinery Flare were verified and inline with the industry standards. Therefore the components change do not constitute "reconstruction" of the flare as defined under 40 CFR Part 60 (New Source Performance Standards) for the purpose of Subpart J applicability.

(b) One (1) fixed roof, insulated, heated cone tank, identified as Tank No. 22B, with a capacity of 1,050,000 gallons and a maximum withdrawal rate of 16,800 gallons per hour of petroleum or residual fuel oil (No.6) with vapor pressure of No. 2 fuel oil or less and exhausting to stack 127 (start construction in second quarter of 2006 and to be completed by November 2006);

(c) One (1) fixed roof, insulated, heated cone tank, identified as Tank No. 173, with a capacity of 1,050,000 gallons and a maximum withdrawal rate of 16,800 gallons per hour of petroleum or residual fuel oil (No.6) with vapor pressure of No. 2 fuel oil or less and exhausting to stack 128 (start construction in third quarter of 2006 and to be completed by March 2007);

(d) One (1) fixed roof, insulated, heated cone tank, identified as Tank No. 174, with a capacity of 1,050,000 gallons and a maximum withdrawal rate of 16,800 gallons per hour of petroleum or residual fuel oil (No.6) with vapor pressure of No. 2 fuel oil or less and exhausting to stack 129 (start construction in second quarter of 2007 and to be completed by December 2007); and

(e) 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.

(f) One (1) boiler identified as B4, 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;

Note: Boiler B4 is intended to supplement existing boilers (B1, B2 and B3) and will not result in increased utilization of any other equipment at the facility.

Under the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (40 CFR 63, Subpart DDDDD), the boiler B4, is considered an existing affected source. The boiler is categorized under the large liquid fuel subcategory.

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.

The following is a list of the modified emission units:

(a) Tank 35 currently services gasoline, will change to distillate service in 2006;

(b) Tank 40 currently services distillate, will change to gasoline service in 2006; and

(c) Tank 46 currently services gasoline, will change to distillate service in 2006 and internal floating roof will be removed at the time of service change.

Enforcement Issues

There are no pending enforcement actions.

Emission Calculations

See Appendix A of this document for detailed emission calculations. (Appendix A, pages 1 through 4).

Permit Level Determination – Part 70

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Potential To Emit						
Pollutant	PM	PM_{10}	SO_2	VOC	CO	NO_x
Emission Unit	Tons/Year	Tons/Year	Tons/Year	Tons/Year	Tons/Year	Tons/Year
Tank 22B	0.00	0.00	0.00	0.59	0.00	0.00
Tank 173	0.00	0.00	0.00	0.59	0.00	0.00
Tank 174	0.00	0.00	0.00	0.59	0.00	0.00
Tank 175	0.00	0.00	0.00	5.15	0.00	0.00
Boiler 4	15.59	14.73	203.95	2.05	31.23	89.31
New Main Refinery Flare	0.47	0.47	210.31	0.34	5.15	1.36
Tank 35*	0.00	0.00	0.00	-4.00	0.00	0.00
Tank 40*	0.00	0.00	0.00	1.87	0.00	0.00
Tank 46*	0.00	0.00	0.00	-4.26	0.00	0.00
Total	**16.06**	**15.20**	**414.26**	**2.92**	**36.38**	**90.67**
Permit level determination threshold	< 25	< 25	> 25	< 25	> 25	> 25

* The PTE of the tank with new service (new content) minus the PTE of the tank with old service (old content).

HAPs	Potential To Emit (tons/year)
Hexane	< 10
TOTAL	< 25

Pollutant	PTE New Emission Units (tons/year)[A]	Net Increase to PTE of Modified Emission Units (tons/year)[B]	Total PTE for New and Modified Units (tons/year)
PM	16.06	0.00	16.06
PM10	15.20	0.00	15.20
SO_2	414.26	0.00	414.26
VOC	9.31	0.00	9.31
CO	36.38	0.00	36.38
NO_X	90.67	0.00	90.67
HAPs	Single HAP < 10 Total HAPs < 25	0.00	Single HAP < 10 Total HAPs < 25

Note:
[A] New emission units include the potential emissions from the new main refinery flare, identified as RCD-1, Boiler identified as B4, and four new tanks identified as Tank No. 22B, 173, 174 and 175. These potential

emissions reflect the before control emissions.

B Modified emission units include three storage tanks identified as Tank No. 35, 40 and 46 with change in service. There is a decrease in VOC emissions in Tank 35 and 46 due to change in service from gasoline to distillate, and an increase in VOC emissions in Tank 40 due to change in service from distillate to gasoline.

This source modification is a significant source modification pursuant to 326 IAC 2-7-10.5 (f)(4) because the potential to emit of SO_2, NOx and CO from the modification are greater than 25 tons per year. Additionally, the modification will be incorporated into the Part 70 Operating Permit through a significant permit modification (No. 129-23090-00003) pursuant to 326 IAC 2-7-12.

Permit Level Determination – PSD

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 source modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential to Emit (tons/year) of Modification After Issuance							
Process/facility	**PM**	**PM10**	**SO_2**	**VOC**	**CO**	**NO_X**	**Single HAP**	**Total HAPs**
Tank 22B	--	--	--	0.59	--	--	0.035 (Toluene)	0.093
Tank 173	--	--	--	0.59	--	--	0.035 (Toluene)	0.093
Tank 174	--	--	--	0.59	--	--	0.035 (Toluene)	0.093
Tank 175	--	--	--	5.15	--	--	0.036 (Hexane)	0.088
Boiler B4 [B]	4.85	4.58	39.65	2.04	31.23	27.78	0.909 (Hexane)	0.951
Main Refinery Flare – RCD-1 (Projected Actual Emissions) [A]	0.00*	0.00*	0.00*	0.00*	0.00*	0.00*	Neg.	Neg.
Main Refinery Flare – RCD-1(Baseline Actual Average Emissions) [A]	0.00*	0.00*	0.00*	0.00*	0.00*	0.00*	Neg.	Neg.
Tank 35 (Projected Actual Emissions)	--	--	--	0.00*	--	--	--	--
Tank 35 (Baseline Actual Average Emissions)	--	--	--	0.00*	--	--	--	--
Tank 40 (Projected Actual Emissions)	--	--	--	0.00*	--	--	--	--
Tank 40 (Baseline Actual Average Emissions)	--	--	--	0.00*	--	--	--	--
Tank 46 (Projected Actual Emissions)	--	--	--	0.00*	--	--	--	--
Tank 46 (Baseline Actual Average Emissions)	--	--	--	0.00*	--	--	--	--
Net Emissions Increase [B]	4.85	4.58	39.65	8.96	31.23	27.78	0.945	1.318
PSD Threshold Level	25	15	40	40	100	40	N/A	N/A

[A] The old main refinery flare is being replaced with a new similar kind flare. Emissions are based on the actual to projected actual (ATPA) test provided by the source (Please refer to TSD Appendix A, page 3 of 4, for more information). Based on the information submitted by Countrymark, the actual emissions from the flare will decrease from historic levels in the future due to 1) installation of a sulfur recovery unit which reduces sulfur dioxide emissions from refinery fuel gas combustion, and 2) increase demand for refinery fuel gas in the future, which will reduce the quantity of gas to be flared.
[B] Although the Boiler B4 will be subject to the same fuel usage limit of 3,214.92 thousand gallons per 12-month rolling period established for Boilers B1, B2, and B3 in SSM 129-18672-00003, issued on February 1, 2005, it has the capability of burning entire fuel usage limit . Therefore, Boiler B4 is being limited to annual fuel usage of 1,000 thousand gallons (with maximum fuel oil sulfur content of 0.5% based on the Subpart Dc). This fuel usage limitation will limit all the criteria pollutant to less than the major PSD threshold level in this source modification. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.
* PTE are considered to be zero (0), if the results of the ATPA test are negative (Please refer to TSD Appendix A, page 3a and 4a, for more information).

This existing source permitted under Part 70 Permit No. 129-7882-00003 (issued on July 23, 2003), is a major stationary source because it is one of the 28 listed source categories (i.e. petroleum refineries) under 326 IAC 2-2, and potential sulfur dioxide (SO_2), volatile organic compound (VOC), carbon monoxide (CO), particulate matter (PM & PM-10) and nitrogen oxide (NOx) emissions after control are greater than 100 tons per year. This modification to an existing major stationary source is not major because the total emissions increase for each pollutant is less than the applicable PSD significant threshold levels.

In Significant Source Modification (129-18672-00003, issued on February 1, 2005, to render the requirements of 326 IAC 2-2 (PSD) not applicable, No. 6 fuel oil usage for boilers B1 through B3 was limited to less than 3,214.92 thousand gallons per year to limit the PM10 emissions less than 15 tons per year. With the addition of boiler B4, the No. 6 fuel usage limit of 3,214.92 thousand gallons per year (established in SSM 129-18672-00003) will stay intact and will apply to all four (4) boilers (B1 through B4). However, Boiler B4 has the capability of burning the entire fuel usage limit, therefore, No. 6 fuel oil usage for Boiler B4 shall be limited to less than 1,000 thousand gallons per year with compliance determined at the end of each month. Therefore, the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2, are not applicable.

Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this modification:

40 CFR 60.40c, Subpart Dc – Standards of Performance of Small Industrial-Commercial-Institutional Steam Generating Units:

The one (1) 84.9 MMBtu/hr boiler, identified as B4, burning refinery fuel gas and No. 6 residual fuel oil as primary fuels and natural gas as secondary fuel, constructed in 2006, is subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60.40c - 60.48c, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) because it is being constructed after June 9, 1989, and has a maximum design heat input capacity greater than 10 MMBtu per hour and less than 100 MMBtu per hour. Therefore, the requirements of the 40 CFR 60.40c, Subpart Dc are included in the permit.

Non applicable portions of the NSPS will not be included in the permit. The boiler, identified as B4 is subject to the following portions of Subpart Dc.

(a) 40 CFR 60.40c
(b) 40 CFR 60.41c
(c) 40 CFR 60.42c (d), (g), (h), (i) & (j)
(d) 40 CFR 60.43c (c), (d), & (e)
(e) 40 CFR 60.44c (a), (b), (c), (e), (f), (g), (h) & (j)
(f) 40 CFR 60.45c (a), (b) & (d)
(g) 40 CFR 60.46c (b), (c), (d) & (f)

(h) 40 CFR 60.47c (a), (b) & (d)
(i) 40 CFR 60.48c (a), (f), (g), (i) & (j)

40 CFR Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels:

(a) The requirements of New Source Performance Standard, 326 IAC 12, 40 CFR Part 60.112b, Subpart Kb (Volatile Organic Liquid Storage Vessels) are not included in this modification for storage tanks identified as 22 B, 173 and 174. Although, each tank is being constructed after the rule applicability date of July 23, 1984 and each has storage capacity greater than 151 m^3 (39,890 gallons), the vapor pressure of gasoline being stored in each tank is less than 3.5 kPa, therefore the rule does not apply.

(b) Storage tanks identified as 175, to be constructed in 2008, is subject to the New Source Performance Standard, 326 IAC 12, 40 CFR Part 60.112b, Subpart Kb (Volatile Organic Liquid Storage Vessels), because the tank is being constructed after the rule applicability date of July 23, 1984, has a storage capacity of greater than 151 m^3 (39,890 gallons) and stores gasoline with a maximum true vapor pressure of greater than 3.5 kPa.

Non applicable portions of the NSPS will not be included in the permit. This source is subject to the following portions of Subpart Kb.

(a) 40 CFR 60.110b
(b) 40 CFR 60.111b
(c) 40 CFR 60.112b (a)
(d) 40 CFR 60.113b (a)
(e) 40 CFR 60.114b
(f) 40 CFR 60.115b (a)
(g) 40 CFR 60.116b (a) through (e)
(h) 40 CFR 60.117b

40 CFR Part 60, Subpart J – Standards of Performance for Petroleum Refineries:

(a) The one (1) 84.9 MMBtu/hr boiler, identified as B4, burning refinery fuel gas and No. 6 residual fuel oil as primary fuels and natural gas as secondary fuel, constructed in 2006, is subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries) because this fuel gas combustion device is a part of the affected facilities in Petroleum Refineries.

Non applicable portions of this NSPS will not be included in the permit. The boiler, identified as B4 and Main Refinery Flare, identified as RCD-1 are subject to the following portions of Subpart J.

(a) 40 CFR 60.100
(b) 40 CFR 60.101
(c) 40 CFR 60.104 (a)
(d) 40 CFR 60.105 (a), (b) & (e)
(e) 40 CFR 60.106 (a) & (e)
(f) 40 CFR 60.107 (d), (e) & (f)
(g) 40 CFR 60.108 (a)
(h) 40 CFR 60.109

The old main refinery flare structure, installed in 1945, is at the end of its recommended service life. It is Countrymark's intent to make a "replacement in kind" and this replacement will not affect the operating capacity of any other units at the refinery. The new flare structure will have the same operating parameters and will be the same diameter, but 25 feet higher. Countrymark also estimates that the capital cost to replace the flare is $515,204. The cost of components which will be replaced as apart of this modification (flare, HKO Drum, and VKO Drum) is $181,200, which is 35.2% of the cost of a replacement unit. Therefore the components change do not constitute "reconstruction" of the flare as defined under 40 CFR Part 60 (New Source Performance

Standards) for the purpose of Subpart J applicability.

40 CFR 63, Subpart DDDDD – Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters:

The one (1) 84.9 MMBtu/hr boiler, identified as B4, burning refinery fuel gas and No. 6 residual fuel oil as primary fuels and natural gas as secondary fuel, constructed in 2006, is subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD because the source is major for HAPs. This boiler is part of the affected source for the large liquid fuel subcategory because it meets the criteria in the definition in 40 CFR 63.7575 for the large liquid fuel subcategory.

Non applicable portions of the NESHAP will not be included in the permit. The boiler, identified as B4 is subject to the following portions of Subpart DDDDD.

(a) 40 CFR 63.7480
(b) 40 CFR 63.7485
(c) 40 CFR 63.7490
(d) 40 CFR 63.7495 (a) & (d)
(e) 40 CFR 63.7499
(f) 40 CFR 63.7500 (a) & (b)
(g) 40 CFR 63.7505 (a) & (c) through (e)
(h) 40 CFR 63.7510 (a) through (c) & (g)
(i) 40 CFR 63.7515 (a) through (g)
(j) 40 CFR 63.7520 (a), (b), (d) & (e) through (g)
(k) 40 CFR 63.7521 (a) through (e)
(l) 40 CFR 63.7530 (a), (c), (d) & (e)
(m) 40 CFR 63.7545 (a), (c), (d) & (e)
(n) 40 CFR 63.7550 (a), (b), (c), (d), (f) & (g)
(o) 40 CFR 63.7555 (a), (c), (d) & (e)
(p) 40 CFR 63.7560 (a), (b) & (c)
(q) 40 CFR 63.7565
(r) 40 CFR 63.7570 (a) & (b)
(s) 40 CFR 63.7575

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63 Subpart DDDDD.

40 CFR 64.2 Compliance Assurance Monitoring (CAM)

Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;
(2) is subject to an emission limitation or standard for that pollutant; and
(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

This source was issued Part 70 Permit No. T129-7882-00003 on July 21, 2003. For this modification, Boiler B4 and Main Refinery Flare, identified as RCD – 1 have potential SO_2 emissions greater than 100 tons per year, however Boiler B4 and Main Refinery Flare has no control device and no emission limitation or standard respectively, therefore the requirements of

40 CFR Part 64, Compliance Assurance Monitoring do not apply. No other emission unit has potential pre-control emissions of a regulated air pollutant that are equal or greater than 100 tons per year. Therefore, the requirements of 40 CFR Part 64, Compliance Assurance Monitoring do not apply.
The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new or modified emission unit involved:

Emission Unit	Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Boiler 4 – SO_2	No	Yes	203.95	10.59	100	No	No
Main Gas Flare - SO_2	No	No	210.31	210.31	100	No	No

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to Boiler B4 and Main Refinery Flare, as part of this modification.

State Rule Applicability Determination

The following state rules are applicable to the source due to the modification:

326 IAC 2-2 (PSD)
PSD applicability is discussed under the Permit Level Determination - PSD section.

326 IAC 2-6 (Emission Reporting)
Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, it is subject to 326 IAC 2-6 (Emission Reporting). The source also has potential to emit greater than or equal to 2,500 tons per year of sulfur dioxide; therefore, an emission statement covering the previous calendar year must be submitted by July 1 annually. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 8-1-6 (New Facilities, General Reduction Requirements)
The requirements of 326 IAC 8-1-6 applies to new facilities (as of January 1, 1980) which have potential emissions of 25 tons or more per year of volatile organic compounds (VOC). The potential VOC emissions from this modification are below the twenty-five (25) tons per year applicability threshold and therefore, none of the new units are subject to the requirements of 326 IAC 8-1-6.

326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)
Storage tanks No. 22 B, 173 and 174, each with capacity greater than 39,000 gallons stores petroleum liquid whose true vapor pressure is less than 1.52 psi, therefore these storage tanks are not subject to the rule.

Storage tank No. 175, petroleum liquid storage tank, to be constructed in 2007, with a capacity greater than 39,000 gallons containing volatile organic liquid whose true vapor pressure is greater than 1.52 pounds per square inch (psi) is subject to the requirements of 326 IAC 8-4-3 (Petroleum Liquid Storage Facilities).

Pursuant to 326 IAC 8-4-3, the Permittee shall maintain records including the following:
(a) the types of volatile petroleum liquids stored;
(b) the maximum true vapor pressure; and
(c) records of the inspections.

These records shall be maintained for a period of two (2) years, and shall be made available to the IDEM, OAQ upon request.

Storage tanks No.35, 40 and 46 are not subject to the requirements of 326 IAC 8-4-3 since these storage tanks were originally constructed prior to rule applicability date of 1980, and the change in tank content does not qualify as a reconstruction.

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)
The source is not subject to the requirements of 326 IAC 8-9 (Volatile Organic Liquid Storage Vessels) because this source is not located in one of the listed counties and was constructed prior to January 1, 1980.

326 IAC 6-2-4 (Particulate Emissions Limitations for Sources of Indirect Heating)
The one (1) 84.9 MMBtu/hr boiler, identified as B4, burning refinery fuel gas and No. 6 residual fuel oil as primary fuels and natural gas as secondary fuel, constructed in 2006, is subject to the particulate matter limitations of 326 IAC 6-2-4. Pursuant to this rule, boiler B4 is limited by the following equation from 326 IAC 6-2-4:

$Pt = 1.09 / Q^{0.26}$ where: Pt = pounds of PM emitted per MMBtu heat input (lb/MMBtu)
Q = total source operating capacity (MMBtu/hr) = 253.9

$Pt = 1.09 / 253.9^{0.26} = 0.25$ lb/MMBtu

The PM emissions from the boiler B4 shall be limited to less than 0.25 lbs PM/MMBtu.

<u>Compliance calculation:</u>
(15.59 tons PM/yr) * (hr/84.9 MMBtu) * (yr/8,760 hrs) * (2,000 lbs/ton) = 0.04 lbs PM/MMBtu

Therefore, the boiler will comply with this rule.

326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations)
Boiler B4 is subject to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations) because the boiler has potential SO_2 emissions greater than 25 tons per year. The sulfur dioxide emissions from the boiler B4, when No. 6 residual fuel oil is used, shall be limited to 1.6 pounds per million British thermal units heat input. This equates to a distillate fuel oil sulfur content limit of 1.70%. Therefore, the sulfur content of the distillate fuel must be less than or equal to 1.70% in order to comply with this rule. Based on the information submitted by the source, the sulfur content of the No. 6 residual fuel oil is 0.5%. Therefore, the burner combustion of No. 6 residual fuel oil complies with the rule.

326 IAC 7-2-1 (Sulfur Dioxide Reporting Requirements)
Pursuant to this rule, the source shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate (pounds SO_2 per MMBtu), to IDEM, OAQ upon request.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark and Floyd Counties)
The source 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.

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

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source=s failure to take the appropriate corrective actions within a specific time period.

The Compliance Determination Requirements applicable to this modification are as follows:

1. The tank identified as No. 175 has applicable compliance monitoring conditions as specified below:

   The Permittee shall comply with the monitoring requirements in 40 CFR 60.116b for the internal floating roof tank identified as 175 and shall maintain the following records for a minimum of two (2) years. The applicable compliance monitoring conditions are specified below:

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

   (b) The Permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage vessel.

   (c) The Permittee 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) 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.

These monitoring conditions are necessary because the tank No.175 must comply with 40 CFR 60.113b (Subpart Kb) and 326 IAC 2-7 (Part 70).

2. The Boiler No. 4 has applicable compliance monitoring conditions as specified below:

(a) Daily visible emission notations of the boiler's exhaust stack (B4) shall be performed during normal daylight operations when exhausting to the atmosphere. 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.

These monitoring conditions are necessary because boiler B4 must operate properly to ensure compliance with 326 IAC 5 (Visibility), 326 IAC 6-2-4 (Particulate Emissions Limitations for Sources of Indirect Heating), and 326 IAC 2-7 (Part 70).

3. The Boiler No. 4 has applicable compliance monitoring conditions as specified below:

Pursuant to 40 CFR 60.105, Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(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 SO_2 and 25 percent oxygen (O2).
(ii) The SO_2 monitoring level equivalent to the H_2S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).
(iii) The performance evaluations for this SO2 monitor under Sec. 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.
(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(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 H_2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H_2S.
(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.
(iii) The performance evaluations for this 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) 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.

(d) 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.

These monitoring conditions are necessary because the Boiler B4 must comply with 40 CFR 60, Subpart J and 326 IAC 2-7 (Part 70).

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. 129-7882-00003. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Change No. 1:

Condition A.2, Emission Units and Pollution Control Equipment Summary, was revised as follows to clarify the descriptions of the emission units:

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

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

***

(d) The following storage vessels:

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
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**;
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 ~~gasoline rvp 13~~ **Distillate**,	1946	046;
40	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,222,388	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of ~~Distillate~~ **gasoline rvp 13**,	1949	051;
46	fixed roof cone tank~~/internal floating roof tank~~,/mechanical primary seal	3,402,000	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of ~~gasoline rvp 13~~ **Distillate**,	1955	057;
***	***	***	***	***	***	***
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;**
175	**fixed roof cone tank/internal floating roof tank,/liquid mounted primary seal**	**2,310,000**	**210,000**	**Petroleum Material with a vapor pressure equivalent to or less than the vapor pressure of 13 rvp gasoline,**	**2007**	**130**

(e) One (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 MMBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 MMBtu/hr), installed in1945 **and replaced in 2006** and exhausting to stack 18;

***

(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 Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (40 CFR 63, Subpart DDDDD), the boiler B4, is considered an existing affected source. The boiler is categorized under the large liquid fuel subcategory.

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.

Change No. 2:

1. All references to IDEM, OAQ's mailing address have been revised as follows:

Indiana Department of Environmental Management
Office of Air Quality
100 North Senate Avenue, ~~P.O. Box 6015~~
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

2. Condition B.8 (Compliance with Permit Conditions) has been removed from the B section and has been added to the Title V title page instead.

3. A statement is added to paragraph (b) of Condition B.9, Certification, in order to clarify that the certification form for each submittal may cover more than one document.

4. Paragraph (a) of Condition B.10, Annual Compliance Certification, was revised to remove "in letter form" so that it does not contradict the Nonrule Policy Document that provides an example for how sources can submit annual compliance certifications.

5. IDEM has determined that the Permittee is not required to keep records of all preventive maintenance. However, where the Permittee seeks to demonstrate that an emergency has occurred, the Permittee must provide, upon request records of preventive maintenance in order to establish that the lack of proper maintenance did not cause or contribute to the deviation. Therefore, IDEM has deleted paragraph (b) of Condition B.11 – Preventive Maintenance and has amended Condition B.12 – Emergency Provisions.

6. Paragraph (a) of Condition B.13, Permit Shield, is revised to remove the word "in" from the second sentence to be consistent with 326 IAC 2-7-15(a).

7. Condition B.13 (Permit Shield) has been revised to delete the non-applicability determinations which were based on construction or modification dates of the emission units.

8. Paragraphs (d) of original Condition B.18, Permit Amendment or Modification was deleted. 40 CFR 89, Appendix A specifically indicates that states are not precluded from regulating the use and operation of nonroad engines, such as regulations on hours of usage, daily mass emission limits, or sulfur limits on fuel; nor are permits regulating such operations precluded, once the engine is no longer new.

9. For clarification purposes, Condition B.20 - Operational Flexibility has been revised.

10. Indiana was required to incorporate credible evidence provisions into state rules consistent with the SIP call published by U.S. EPA in 1997 (62 FR 8314). Indiana has incorporated the credible evidence provision in 326 IAC 1-1-6. This rule is effective March 16, 2005; therefore, the older condition has been replaced with a new condition.

11. The 326 IAC 6-3 revisions that became effective on June 12, 2002 were approved into the State Implementation Plan on September 23, 2005. These rules replace the previous version of 326 IAC 6-3 (Process Operations) that had been part of the SIP; therefore, the requirements of the previous version of 326 IAC 6-3-2 are no longer applicable to this source.

12. The last sentence of Conditions C.3 and C.5, Open Burning and Fugitive Dust Emissions, were deleted because the open burning and the fugitive dust emissions provisions are now federally enforceable and are included in Indiana's State Implementation Plan (SIP).

13. In order to avoid duplication of requirements which may be included in D sections, Condition C.6– Operation of Equipment has been removed from the permit.

14. Condition C.9 (Compliance Monitoring) has been revised to incorporate the requirements

for new units.

15. Upon further review, IDEM has determined that no additional monitoring will be required during COM downtime, until the COM has been down for twenty-four (24) hours. This allows the Permittee to focus on the task of repairing the COM during the first twenty-four (24) hour period. After twenty-four (24) hours of COM downtime, the Permittee will be required to conduct Method 9 readings for thirty (30) minutes. Once Method 9 readings are required to be performed, the readings should be performed twice per day at least 4 or 6 hours apart, rather than once every four (4) hours, until a COMS is back in service.

16. IDEM realizes that the specifications of Condition C.14 - Pressure Gauge and Other Instrument Specifications, can only be practically applied to analog units, and has therefore clarified the condition to state that the condition only applies to analog units. Upon further review, IDEM has also determined that the accuracy of the instruments is not nearly as important as whether the instrument has a range that is appropriate for the normal expected reading of the parameter. Therefore, the language in Condition C.14 has been revised (see the changes in the section of Proposed Changes).

17. IDEM has reconsidered the requirement to develop and follow a Compliance Response Plan (Condition C.17). The Permittee will still be required to take reasonable response steps when a compliance monitoring parameter is determined to be out of range or abnormal. Replacing the requirement to develop and follow a Compliance Response Plan with a requirement to take reasonable response steps will ensure that the control equipment is returned to proper operation as soon as practicable, while still allowing the Permittee the flexibility to respond to situations that were not anticipated. Therefore, the condition for “Compliance Response Plan” has been replaced by the condition for “Response to Excursions or Exceedances”. The Section D conditions that refer to this condition have been revised to reflect the new condition title (see the changes in the section of Proposed Changes).

18. Rule cites were added to the title line of original Condition C.20, General Record Keeping Requirements, paragraph (a) was revised to clarify how records may be kept, and paragraph (c) was added to clarify record keeping requirements related to 326 IAC 2-2 and 326 IAC 2-3.

19. Paragraph (e) of Condition C.21, General Reporting Requirements, was revised to clarify the reporting periods and the meaning of “calendar year”. Rule cites were added to the title line and paragraphs (f) and (g) were added to clarify reporting requirements related to 326 IAC 2-2 and 326 IAC 2-3. Paragraph (h) was added to clarify that documentation required by this permit should be made available to IDEM, OAQ upon request.

20. IDEM has determined that it is the Permittee’s responsibility to include routine control device inspection requirements in the applicable preventive maintenance plan. Since the Permittee is in the best position to determine the appropriate frequency of control device inspections and the details regarding which components of the control device should be inspected, the conditions requiring control device inspections have been removed from the permit. In addition, the requirement to keep records of the inspections has been removed.

~~**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]~~

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

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

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

~~(a) 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 and Evansville EPA, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.~~

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

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

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

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

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

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

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

~~(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ, may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The submittal by the Permittee does require the certification by the Aresponsible official@ as defined by 326 IAC 2-7-1(34). Upon request, the Permittee shall also furnish to IDEM, OAQ, copies of records required to be kept by this permit.~~

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

~~B.8 Compliance with Permit Conditions [326 IAC 2-7-5(6)(A)] [326 IAC 2-7-5(6)(B)]~~

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

~~(1) Enforcement action;~~

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

~~(3) Denial of a permit renewal application.~~

~~(b) Noncompliance with any provisions of this permit, except any provision specifically~~

~~designated as not federally enforceable, constitutes a violation of the Clean Air Act.~~

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

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

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

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

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

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

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

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

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

~~and~~

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

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

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

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

~~(2) The compliance status;~~

~~(3) Whether compliance was continuous or intermittent;~~

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

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

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

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

~~(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, including the following information on each facility:~~

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

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

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

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

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

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

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

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

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

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

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

~~(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the~~

~~affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:~~

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

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

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

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

~~Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or~~
~~Telephone Number: 317-233-5674 (ask for Compliance Section)~~
~~Facsimile Number: 317-233-5967~~
~~Telephone Number: 812-436-2570~~
~~Facsimile Number: 812-436-2572~~

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

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

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

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

~~(A) A description of the emergency;~~

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

~~(C) Corrective actions taken.~~

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

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

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

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

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

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

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

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

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

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

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

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

~~Federal Rule Applicability (Plant 1)~~

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

~~(2) (i) The one (1) FCCU regenerator, with a maximum heat input rate of 3.2 mmBtu/hr of process gas and maximum throughput rate of 380 barrels of fresh crude feed per hour, identified as V 5, installed in 1950, and refinery fuel gas combustion units (FCCU preheater, Main refinery flare, Crude heater, Unifier heater, Alkylation unit heat, Auxiliary crude heater, Platformer stabilizer reb, Boilers Nos. 1, 2 and 3, Vacuum heater husky) are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60.100, Subpart J - Standards of Performance for Petroleum Refineries), because all units commenced construction or modification before the rule applicability date of June 11, 1973.~~

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

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

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

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

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

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

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

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

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

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

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

~~State Rule Applicability Entire Source (Plant 1)~~

~~(11) 326 IAC 2 2 (Prevention of Significant Deterioration): This rule applies to sources commencing construction after August 7, 1977. This source was constructed~~

~~prior to the applicability date but potential emissions after control were greater than 100 tons per year as of August 7, 1977 as stated above. Therefore, the source was a major PSD source for purposes of determining applicability of this rule to future modifications. Each of the modifications after August 7, 1977, had potential to emit VOC of less than 40 tons per year. Therefore, this rule does not apply.~~

~~State Rule Applicability - Individual Facilities (Plant 1)~~

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

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

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

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

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

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

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

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

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

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

~~(d) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the~~

~~permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.~~

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

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

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

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

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

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

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

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

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

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

~~(1) incorporated as originally stated,~~

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

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

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

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

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

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

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

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

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

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

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

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

~~(1) That this permit contains a material mistake.~~

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

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

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

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

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

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

~~Request for renewal shall be submitted to:~~

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

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

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

~~(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the~~

~~shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.~~

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

~~(4) The Permittee notifies the:~~

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

~~and~~

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

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

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

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

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

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

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

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

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

~~B.22 Inspection and Entry [326 IAC 2-7-6] [IC 13-14-2-2] [IC 13-30-3-1]~~

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

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

~~permit;~~

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

~~B.26 Term of Conditions [326 IAC 2-1.1-9.5]~~

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

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

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

~~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 [40 CFR 52 Subpart P] [326 IAC 6-3-2]~~

~~(a) Pursuant to 40 CFR 52, Subpart P, particulate matter emissions 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.~~

~~(b) 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. This condition is not federally enforceable.~~

~~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. 326 IAC 4-1-3 (a)(2)(A) and (B) are not federally enforceable.~~

~~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. 326 IAC 9-1-2 is not federally enforceable.~~

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

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

~~C.6 Operation of Equipment [326 IAC 2-7-6(6)]~~

~~Except as otherwise provided by statute or rule, or in this permit, all air pollution control equipment listed in this permit and used to comply with an applicable requirement shall be operated at all times that the emission units vented to the control equipment are in operation.~~

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

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

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

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

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

~~(A) Asbestos removal or demolition start date;~~

~~(B) Removal or demolition contractor; or~~

~~(C) Waste disposal site.~~

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

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

~~All required notifications shall be submitted to:~~

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

~~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 14-10-4, 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 that the inspector be accredited, pursuant to the provisions of 40 CFR 61, Subpart M, is federally enforceable.~~

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

~~C.8 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 Data Section, Office of Air Quality~~
~~100 North Senate Avenue, P. O. Box 6015~~
~~Indianapolis, Indiana 46206-6015~~

~~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 and Evansville EPA not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ, and Evansville EPA, if the source submits to IDEM, OAQ, a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.~~

~~Compliance Requirements [326 IAC 2-1.1-11]~~

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

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

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

~~C.10 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]~~

~~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. 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 Branch, Office of Air Quality~~
~~100 North Senate Avenue, P. O. Box 6015~~
~~Indianapolis, Indiana 46206-6015~~
~~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.11 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]~~

~~(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.~~

~~(b) In the event that a breakdown of a continuous opacity 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 opacity monitor (COM) is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, a calibrated backup COM shall be brought online within four (4) hours of shutdown of the primary COM, if possible. If this is not possible, visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of one (1) hour beginning four (4) hours after the start of the malfunction or down time.~~

~~(1) If the reading period begins less than one hour before sunset, readings shall be performed until sunset. If the first required reading period would occur between sunset and sunrise, the first reading shall be performed as soon as there is sufficient daylight.~~

~~(2) Method 9 opacity readings shall be repeated for a minimum of one (1) hour at least once every four (4) hours during daylight operations, until such time that the continuous opacity monitor is back in operation.~~

~~(3) All of the opacity readings during this period shall be reported in the Quarterly Deviation and Compliance Monitoring Reports.~~

~~(d) 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, 40 CFR 63.1572 (a).~~

~~C.12 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. In addition, prompt corrective action shall be initiated whenever indicated.~~

~~(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.13 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.14 Pressure Gauge and Other Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]~~

~~(a) Whenever a condition in this permit requires the measurement of pressure drop across any part of the unit or its control device, the gauge employed shall have a scale such that the expected normal reading shall be no less than twenty percent (20%) of full scale and be accurate within plus or minus two percent (±2%) of full scale reading.~~

~~(b) Whenever a condition in this permit requires the measurement of a flow rate the instrument employed shall have a scale such that the expected normal reading shall be no less than twenty percent (20%) of full scale and be accurate within plus or minus two percent (±2%) of full scale reading.~~

~~(c) The Preventive Maintenance Plan for the pH meter shall include calibration using known standards. The frequency of calibration shall be adjusted such that the typical error found at calibration is less than one pH point.~~

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

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

~~C.15 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]~~

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

~~(a) The Permittee shall 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 Branch, Office of Air Quality~~
~~100 North Senate Avenue, P.O. Box 6015~~
~~Indianapolis, Indiana 46206-6015~~

~~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, and Evansville EPA, 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, and Evansville EPA, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]~~

~~C.16 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]~~

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

~~C.17 Compliance Response Plan - Failure to Take Response Steps [326 IAC 2-7-5] [326 IAC 2-7-6]~~

~~(a) The Permittee is required to prepare a Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. A CRP shall be submitted to IDEM, OAQ and Evansville EPA, upon request and Evansville EPA. The CRP shall be prepared within ninety (90) days after issuance of this permit by the Permittee, supplemented from time to time by the Permittee, maintained on site, and comprised of:~~

~~(1) Reasonable response steps that may be implemented in the event that a response step is needed pursuant to the requirements of Section D of this permit; and an expected timeframe for taking reasonable response steps.~~

~~(2) If, at any time, the Permittee takes reasonable response steps that are not set forth in the Permittee's current Compliance Response Plan and the Permittee documents such response in accordance with subsection (e) below, the Permittee shall amend its Compliance Response Plan to include such response steps taken.~~

~~(b) For each compliance monitoring condition of this permit, reasonable response steps shall be taken when indicated by the provisions of that compliance monitoring condition as follows:~~

~~(1) Reasonable response steps shall be taken as set forth in the Permittee's current Compliance Response Plan; or~~

~~(2) If none of the reasonable response steps listed in the Compliance Response Plan is applicable or responsive to the excursion, the Permittee shall devise and implement additional response steps as expeditiously as practical. Taking such additional response steps shall not be considered a deviation from this permit so long as the Permittee documents such response steps in accordance with this condition.~~

~~(3) If the Permittee determines that additional response steps would necessitate that the emissions unit or control device be shut down, the IDEM, OAQ shall be promptly notified of the expected date of the shut down, the status of the applicable compliance monitoring parameter with respect to normal, and the results of the actions taken up to the time of notification.~~

~~(4) Failure to take reasonable response steps shall constitute a violation of the permit.~~

~~(c) The Permittee is not required to take any further response steps for any of the following reasons:~~

~~(1) A false reading occurs due to the malfunction of the monitoring equipment and prompt action was taken to correct the monitoring equipment.~~

~~(2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for a minor permit modification to the permit, and such request has not been denied.~~

~~(3) An automatic measurement was taken when the process was not operating.~~

~~(4) The process has already returned or is returning to operating within "normal" parameters and no response steps are required.~~

~~(d) When implementing reasonable steps in response to a compliance monitoring condition, if the Permittee determines that an exceedance of an emission limitation has occurred, the Permittee shall report such deviations pursuant to Section B-Deviations from Permit Requirements and Conditions.~~

~~(e) The Permittee shall record all instances when response steps are taken. In the event of an emergency, the provisions of 326 IAC 2-7-16 (Emergency Provisions) requiring prompt corrective action to mitigate emissions shall prevail.~~

~~(f) Except as otherwise provided by a rule or provided specifically in Section D, all monitoring as required in Section D shall be performed when the emission unit is operating, except for time necessary to perform quality assurance and maintenance activities.~~

~~C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]~~

~~(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall 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 and 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 documents submitted pursuant to this condition do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

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

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

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

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

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

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

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

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

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

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

~~(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.~~

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

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

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

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

~~(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.~~

~~**Stratospheric Ozone Protection**~~

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

~~Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with 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 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 Branch, Office of Air Quality
100 North Senate Avenue
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) The Permittee shall maintain and implement Preventive Maintenance Plans (PMPs) for the source as described in 326 IAC 1-6-3. At a minimum, the PMPs shall include:

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

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

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

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

**Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
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 Branch, Office of Air Quality
100 North Senate Avenue
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.

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

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

(c) If there is a reasonable possibility that 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 Clean Unit, 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)) may result in significant emissions increase 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) Before beginning actual construction of the "project" (as defined in 326 IAC 2-2-1 (qq) and/or 326 IAC 2-3-1 (ll)) 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/or 326 IAC 2-3-1(mm)(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 of 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 "responsible official" as defined by 326 IAC 2-7-1(34).

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

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
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 "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 other than Electric Utility Steam Generating Unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline

actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (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 other than Electric Utility Steam Generating 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
Air Compliance Section, Office of Air Quality
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.

Change No. 3:

Equipment description in Section D.3 has been revised to add new storage tanks and change of service for others.

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

The following storage vessels:

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

Tank ID	Tank Description	Max. Capacity (gallons)	Max. Withdrawal Rate (gal/hr)	Material Stored	Construction Date	Stack ID
***	***	***	***	***	***	***
18	internal floating roof tank,/mechanical primary seal	1,052,013	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	2003	037;
19	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	616,938	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	032;
21	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	1,002,750	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1941	034;
22A	fixed roof cone tank	1,050,000	84,000	hydrocarbon with vapor pressure of No. 2 fuel oil o less	2003	120;
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;**
***	***	***	***	***	***	***
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 ~~gasoline rvp 13~~ **Distillate**,	1946	046;
36	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	2,261,954	336,000	hydrocarbon with vapor pressureequal to or less than the vaporpressure 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	hydrocarbon with vapor pressure equal to or less than the vapor pressure of ~~Distillate~~ **13 RVP gasoline**,	1949	051;
41	fixed roof cone tank/internal floating roof tank,/lmechanical primary seal	2,204,244	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1949	052;
42	fixed roof cone tank	2,261,574	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet 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~~/internal floating roof tank~~,/mechanical primary seal	3,402,000	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of ~~gasoline rvp 13~~ **Distillate**,	1955	057;
Tank ID	**Tank Description**	**Max. Capacity (gallons)**	**Max. Withdrawal Rate (gal/hr)**	**Material Stored**	**Construction Date**	**Stack ID**
47	fixed roof cone tank/internal floating roof tank,/mechanical primary seal	5,040,000	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1976	058;
48	fixed roof cone tank/external floating roof tank /mechanical primary seal	4,032,000	336,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1958	059;
***	***	***	***	***	***	***
168	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha,	1988	112;
169	fixed roof cone tank	16,800	168,000	hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline,	1989	113;
125	fixed roof cone tank	157,000	6,000	hydrocarbon with vapor pressure of No.2 fuel oil or less	2005	015;
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;**

Change No. 4:

Upon further review, IDEM has determined that once per day monitoring of visible emission notations is generally sufficient to ensure proper operation of the emission unit. IDEM has also determined that monitoring these parameters once per day is sufficient to satisfy the requirements of the Part 70 rules at 326 IAC 2-7-5 and 326 IAC 2-7-6. Conditions D.5.7 has been also revised to replace the reference to Compliance Response Plan with the Response to Excursions or Exceedances.

D.5.7 Visible Emissions Notations

(a) Visible emission notations of the boiler stacks (B1, B2 and B3) exhaust shall be performed once per ~~shift~~ **day** during normal daylight operations ~~when exhausting to the atmosphere and~~ while combusting fuel oil. A trained employee shall record whether emissions are normal or abnormal.

***

(e) ~~The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed.~~ **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 - ~~Compliance Response Plan - Failure to Take Response Steps~~ **Response to Excursions or Exceedances**, shall be considered a ~~violation of~~ **deviation of** this permit.

Change No. 5:

Old main refinery flare has been removed from Section D.5 and placed in a new Section E.4.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) one (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 **and replaced in 2006** and exhausting to stack 118;
(b) one (1) crude heater equipped with the Low-NOx burner, with a maximum heat input rate of 131 million British Thermal Units per hour (mmBtu/hr) of No. 6 residual oil and process gas, identified as C-II, exhausting to stack 1;
(c) one (1) unifiner heater, with a maximum heat input rate of 20 mmBtu/hr of process gas, identified as H-H5 and exhausting to stack 2;
(d) one (1) cycle oil heater, with a maximum heat input rate of 10 mmBtu/hr of process gas, identified as H-H2 and exhausting to stack 3;
(e) one (1) naphtha splitter heater, with a maximum heat input rate of 12.2 mmBtu/hr of process gas, identified as H-H3 and exhausting to stack 4;
(f) one (1) vacuum heater, with a maximum heat input rate of 14.1 mmBtu/hr of process gas, identified as V-IV and exhausting to stack 5;
(g) one (1) old Platformer heater, with a maximum heat input rate of 29 mmBtu/hr of process gas, identified as P-H1 and exhausting to stack 6;
(h) one (1) alkylation unit heater, with a maximum heat input rate of 13.2 mmBtu/hr of process gas, identified as A-H1 and exhausting to stack 7;
(i) one (1) auxiliary crude heater, with a maximum heat input rate of 10.1 mmBtu/hr of process gas, identified as C-I and exhausting to stack 11;
(j) one (1) platformer stabilizer reb, with a maximum heat input rate of 5.92 mmBtu/hr of process gas, identified as P-H2 and exhausting to stack 12;
(k) one (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;
(l) one (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;
(m) one (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;
(n) one (1) vacuum heater husky, with a maximum heat input rate of 6.27 mmBtu/hr of No. 6 residual oil and process gas, identified as VIII and exhausting to stack 64.
(o) one (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no sour water stripper overhead off-gas combustion), installed in 1945 and exhausting to stack 9.

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

Change No. 6:

New applicable requirements for 40 CFR Part 63, Subpart DDDDD for Industrial, Commercial, and Institutional Boilers and Process Heaters for Boiler B4 have been added to Section E.1 as follows:

SECTION E.1 FACILITY OPERATION CONDITIONS

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

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 Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (40 CFR 63, Subpart DDDDD), the boiler B4, is considered an existing affected source. The boiler is categorized under the large liquid fuel subcategory.

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

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

E.1.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.7565, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 for the boiler, B4, as specified in Table 10 of 40 CFR 63, Subpart DDDDD in accordance with schedule in 40 CFR 63 Subpart DDDDD.

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

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

E.1.2 Applicability of Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP Requirements [40 CFR Part 63, Subpart DDDDD]

The provisions of 40 CFR Part 63, Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) apply to the affected source. A copy of this rule is available on the US EPA Air Toxics Website at www.epa.gov/ttn/atw/boiler/boilerpg.html.

E.1.3 Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP Requirements [40 CFR Part 63, Subpart DDDDD]

Pursuant to CFR Part 63, Subpart DDDDD, the Permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters for the boiler, B4, upon startup.

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491.

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in §63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or constructed boiler or process heater, you must comply with the subpart no later by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

Sec. 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in Sec. 63.7575.

Sec. 63.7500 What emission limits, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under Sec. 63.7507.

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

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

Sec. 63.7505 What are my general requirements for complying with this subpart?

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

(c) You 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, you must demonstrate compliance using performance testing.

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

(1) For each continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a sitespecific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this sitespecific monitoring plan at least 60 days before your initial performance evaluation of your 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 your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.
(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (c)(3), and c)(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) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.
4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

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

Sec. 63.7510 What are my initial compliance requirements and by what date must I conduct them?

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

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

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

(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

Sec. 63.7515 When must I conduct subsequent performance tests or fuel analyses?

(a) You must conduct all applicable performance tests according to Sec. 63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

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

(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you 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, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

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

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

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

(f) You must conduct three separate test runs for each performance test required in this section, as specified in Sec. 63.7(e)(3). Each test run must last at least 1 hour.

(g) To determine compliance with the emission limits, you 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.

Sec. 63.7521 What fuel analyses and procedures must I use?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.

(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) Transfer all samples to a clean plastic bag for further processing.

(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) Throughly mix and pour the entire composite sample over a clean plastic sheet.

(2) Break sample pieces larger than 3 inches into smaller sizes.

(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) Separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) Grind the sample in a mill.

(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

Sec. 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

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

(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in Sec. 63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to Sec. 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input (Cinput) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 5 of this section.

$$Cl_{input} = \sum_{i=1}^{n} \left[(C_i)(Q_i) \right] \qquad \text{(Eq. 5)}$$

Where:
Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to Sec. 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ``1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in Sec. 63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in Sec. 63.7575, as your operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in Sec. 63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in Sec. 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to Sec. 63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.

$$P_{90} = \text{mean} + (SD \times t) \qquad \text{(Eq. 8)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to Sec. 63.7521, in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left[(C_{i90})(Q_i)(1.028) \right] \qquad \text{(Eq. 9)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ``1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

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

Sec. 63.7545 What notifications must I submit and when?

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

(c) As specified in Sec. 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in Sec. 63.7530(a), you must submit a Notification of Compliance Status according to Sec. 63.9(h)(2)(ii). For each initial compliance demonstration, you 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 Sec. 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.

(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.

(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

Sec. 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under Sec. 63.10(a), you 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 this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in Sec. 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 your source in Sec. 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 your source in Sec. 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), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.

(1) Company name and address.

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

(3) Date of report and beginning and ending dates of the reporting period.
(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of Sec. 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If

you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of Sec. 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of Sec. 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of Sec. 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of Sec. 63.7530, the maximum TSM input operating limit using Equation 6 of Sec. 63.7530, or the maximum mercury input operating limit using Equation 7 of Sec. 63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.

(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in Sec. 63.10(d)(5)(i).

(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(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 you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. 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 you 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.

(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 you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you 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 Sec. 63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

Sec. 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

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

(2) The records in Sec. 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 Sec. 63.10(b)(2)(viii).

(c) You 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 you.

(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of Sec. 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 9 of Sec. 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. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of Sec. 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 11 of Sec. 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. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If your 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, you must keep the records in paragraphs (e)(1) and (2) of this section.

(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.

Sec. 63.7560 In what form and how long must I keep my records?

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

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

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

Sec. 63.7565 What parts of the General Provisions apply to me?

Appendix B to this subpart shows which parts of the General Provisions in Sec. Sec. 63.1 through 63.15 apply to you.

Sec. 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in Sec. 63.7500(a) and (b) under Sec. 63.6(g).

(2) Approval of alternative opacity emission limits in Sec. 63.7500(a) under Sec. 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under Sec. 63.7(e)(2)(ii) and (f) and as defined in Sec. 63.90.

(4) Approval of major change to monitoring under Sec. 63.8(f) and as defined in Sec. 63.90.

(5) Approval of major change to recordkeeping and reporting under Sec. 63.10(f) and as defined in Sec. 63.90.

Sec. 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in Sec. 63.2 (the General Provisions), and in this section as follows:

Annual capacity factor **means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.**

Bag leak detection system **means an instrument that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.**

Biomass fuel **means unadulterated wood as defined in this subpart, wood residue, and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.**

Blast furnace gas fuel-fired boiler or process heater **means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.**

Boiler **means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.**

Coal **means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388-991 .\1\, ``Standard Specification for Classification of Coals by Rank \1\'' (incorporated by reference, see Sec. 63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.**

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 (6,000 Btu per pound) on a dry basis.**

Commercial/institutional boiler **means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.**

Construction/demolition material **means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.**
Deviation. (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil **means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1'' (incorporated by reference, see Sec. 63.14(b)).**

Dry scrubber **means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.**

Electric utility steam generating unit **means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.**

Electrostatic precipitator **means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles collecting surface, and transporting the particles into a hopper.**

Fabric filter **means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.**

Federally enforceable **means all limitations and conditions that are enforceable by the EPA 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.**

Firetube boiler **means a boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes.**

Fossil fuel **means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials.**

Fuel type **means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.**

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Heat input **means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.**

Hot water heater **means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210[deg]F (99[deg]C).**

Industrial boiler **means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.**

Large gaseous fuel subcategory **includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.**

Large liquid fuel subcategory **includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.**

Large solid fuel subcategory **includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.**

Limited use gaseous fuel subcategory **includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.**

***Limited use liquid fuel subcategory* includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.**

***Limited use solid fuel subcategory* includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.**

***Liquid fossil fuel* means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.**

***Liquid fuel* includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.**

***Minimum pressure drop* means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.**

***Minimum scrubber effluent pH* means 90 percent of the lowest test-run average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.**

***Minimum scrubber flow rate* means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.**

***Minimum sorbent flow rate* means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.**

***Minimum voltage or amperage* means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.**

***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) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-03a, ``Standard Specification for Liquid Petroleum Gases'' (incorporated by reference, see Sec. 63.14(b)).

***Opacity* means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.**

***Particulate matter* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.**

***Period of natural gas curtailment or supply interruption* means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.**

Process heater **means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.**

Residual oil **means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396-02a, ``Standard Specifications for Fuel Oils 1'' (incorporated by reference, see Sec. 63.14(b)).**

Responsible official **means responsible official as defined in 40 CFR 70.2.**

Small gaseous fuel subcategory **includes any firetube boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and any boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.**

Small liquid fuel subcategory **includes any firetube boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and any boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.**

Small solid fuel subcategory **includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.**

Solid fuel **includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.**

Temporary boiler **means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.**

Total selected metals **means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.**

Unadulterated wood **means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.**

Waste heat boiler **means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.**

Watertube boiler **means a boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes.**

Wet scrubber **means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.**

Work practice standard **means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.**

Tables to Subpart DDDDD of Part 63

TABLE 1 TO SUBPART DDDDD OF PART 63.—EMISSION LIMITS AND WORK PRACTICE STANDARDS

As stated in § 63.7500, you must comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
4. New reconstructed large liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0005 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).

TABLE 2 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITHPARTICULATE MATTER EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	You must meet these operating limits
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
2. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

4. Any other control type	**This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).**

TABLE 4 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH HYDROGEN CHLORIDE EMISSION LIMITS

As stated in § 63.7500, you must comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet scrubber control	Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
2. Dry scrubber control	Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
3. Fuel analysis	Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to § 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.

TABLE 5 TO SUBPART DDDDD OF PART 63.—PERFORMANCE TESTING REQUIREMENTS

As stated in § 63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 26 or 26A in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
5. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of thischapter.

	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	c. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)) when the fuel is natural gas.

TABLE 6 TO SUBPART DDDDD OF PART 63.—FUEL ANALYSIS REQUIREMENTS

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources:

To conduct a fuel analysis for the following pollutant	You must	Using
3. Hydrogen chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	SW–846–9250 or ASTM E776–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

TABLE 7 TO SUBPART DDDDD OF PART 63.—ESTABLISHING OPERATING LIMITS

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	**And your operating limits are based on**	**You must**	**Using**	**According to the following requirements**
1. Particulate matter, mercury, or total selected metals.	**a. Wet scrubber operating parameters.**	**i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).**	**(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.**	**(a) You must collect pressure drop and liquid flowrate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.**

	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control).	**i. Establish a site-specific minimum voltage and secondary current or total power input according to § 63.7530(c).**	**(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.**	**(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.**
2. Hydrogen Chloride	**a. Wet scrubber operating parameters.**	**i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).**	**(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test.**	**(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.**

	b. Dry scrubber operating parameters.	**i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(c).**	**(1) Data from the sorbent injection rate monitors and hydrogen chloride performance test.**	**(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.**

TABLE 9 TO SUBPART DDDDD OF PART 63.—REPORTING REQUIREMENTS

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance report	a. Information required in § 63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i)	Semiannually according to the requirements in § 63.7550(b).
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in § 63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications.	Yes.
§63.2	Definitions	Definitions for part 63 standards.	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards.	Yes.
§63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability.	Yes.
§63.5	Construction/Reconstruction.	Applicability; applications; approvals.	Yes.
§63.6(a)	Applicability	GP apply unless compliance extension; and GP apply to area sources that become major.	Yes.
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed sources.	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f).	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal.	Yes.
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major.	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source.	Yes.
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources.	Comply according to date in subpart, which must be no later than 3 years after effective date; and for 112(f) standards, comply within 90 days of effective date unless compliance extension.	Yes.
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major.	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years).	Yes.
§63.6(d)	[Reserved]		
§63.6(e)(1)-(2)	Operation & Maintenance.	Operate to minimize emissions at all times; and Correct malfunctions as soon as practicable; and Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met.	Yes.
§63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP).	Requirement for SSM and startup, shutdown, malfunction plan; and content of SSMP.	Yes.
§63.6(f)(1)	Compliance Except During SSM.	Comply with emission standards at all times except during SSM.	Yes.
§63.6(f)(2)-(3)	Methods for Determining Compliance.	Compliance based on performance test, operation and maintenance plans, records, inspection.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard.	Yes.
§63.6(h)(1)	Compliance with Opacity/VE Standards.	Comply with opacity/VE emission limitations at all times except during SSM.	Yes.
§63.6(h)(2)(i)	Determining Compliance with Opacity/Visible Emission (VE) Standards.	If standard does not state test method, use Method 9 for opacity and Method 22 for VE.	No.
§63.6(h)(2)(ii)	[Reserved]		
§63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart.	Yes.
§63.6(h)(3)	[Reserved]		
§63.6(h)(4)	Notification of Opacity/VE Observation Date.	Notify Administrator of anticipated date of observation.	No.
§63.6(h)(5)(i),(iii)-(v)	Conducting Opacity/VE Observations.	Dates and Schedule for conducting opacity/VE observations.	No.
§63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times.	Must have at least 3 hours of observation with thirty, 6-minute averages.	No.
§63.6(h)(6)	Records of Conditions During Opacity/VE observations.	Keep records available and allow Administrator to inspect.	No.
§63.6(h)(7)(i)	Report continuous opacity monitoring system Monitoring Data from Performance Test.	Submit continuous opacity monitoring system data with other performance test data.	Yes.
§63.6(h)(7)(ii)	Using continuous opacity monitoring system instead of Method 9.	Can submit continuous opacity monitoring system data instead of Method 9 results even if subpart requires Method 9, but must notify Administrator before performance test.	No.
§63.6(h)(7)(iii)	Averaging time for continuous opacity monitoring system during performance test.	To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages.	Yes.
§63.6(h)(7)(iv)	Continuous opacity monitoring system requirements.	Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§63.8(e), continuous opacity monitoring systems are properly maintained and operated according to §63.8(c) and data quality as §63.8(d).	Yes.
§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards.	Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered.	Yes.
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance.	Yes.
§63.6(h)(9)	Adjusted Opacity Standard.	Procedures for Administrator to adjust an opacity standard.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.6(i)(1)-(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§63.6(j)	Presidential Compliance Exemption.	President may exempt source category from requirement to comply with rule.	Yes.
§63.7(a)(1)	Performance Test Dates.	Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations.	Yes.
§63.7(a)(2)	Performance Test Dates	New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance	Yes.
§63.7(a)(2)(ii-viii)	[Reserved]		
§63.7(a)(2)(ix)	Performance Test Dates	1. New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance; and 2. If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard.	Yes. No.
§63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA Section 114 at any time.	Yes.
§63.7(b)(1)	Notification of Performance Test.	Must notify Administrator 60 days before the test.	No.
§63.7(b)(2)	Notification of Rescheduling.	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date.	Yes.
§63.7(c)	Quality Assurance/Test Plan.	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: test plan approval procedures; and performance audit requirements; and internal and external QA procedures for testing.	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities.	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests.	1. Performance tests must be conducted under representative conditions; and 2. Cannot conduct performance tests during SSM; and 3. Not a deviation to exceed standard during SSM; and 4. Upon request of Administrator, make available records necessary to determine conditions of performance tests.	No. Yes. Yes. Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.7(e)(2)	Conditions for Conducting Performance Tests.	Must conduct according to rule and EPA test methods unless Administrator approves alternative.	Yes.
§63.7(e)(3)	Test Run Duration	Must have three separate test runs; and Compliance is based on arithmetic mean of three runs; and conditions when data from an additional test run can be used.	Yes.
§63.7(e)(4)	Interaction with other sections of the Act.	Nothing in §63.7(e)(1) through (4) can abrogate the Administrator's authority to require testing under Section 114 of the Act.	Yes.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method.	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; and must submit performance test data 60 days after end of test with the Notification of Compliance Status; and keep data for 5 years.	Yes.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test.	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements.	Subject to all monitoring requirements in standard.	Yes.
§63.8(a)(2)	Performance Specifications.	Performance Specifications in appendix B of part 60 apply.	Yes.
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in §63.11 apply.	No.
§63.8(b)(1)(i)-(ii)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§63.8(b)(1)(iii)	Monitoring	Flares not subject to this section unless otherwise specified in relevant standard.	No.
§63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems.	Specific requirements for installing monitoring systems; and must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise; and if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup.	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance.	Maintain monitoring system in a manner consistent with good air pollution control practices.	Yes.
§63.8(c)(1)(i)	Routine and Predictable SSM.	Maintain and operate CMS according to §63.6(e)(1).	Yes.
§63.8(c)(1)(ii)	SSM not in SSMP	Must keep necessary parts available for routine repairs of CMSs.	Yes.
§63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	Must develop and implement an SSMP for CMSs.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.8(c)(2)-(3)	Monitoring System Installation.	Must install to get representative emission and parameter measurements; and must verify operational status before or at performance test.	Yes.
§63.8(c)(4)	Continuous Monitoring System (CMS) Requirements.	CMSs must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts.	No.
§63.8(c)(4)(i)	Continuous Monitoring System (CMS) Requirements.	Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period.	Yes.
§63.8(c)(4)(ii)	Continuous Monitoring System (CMS) Requirements.	Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period.	No.
§63.8(c)(5)	Continuous Opacity Monitoring system (COMS) Requirements.	Must do daily zero and high level calibrations.	Yes.
§63.8(c)(6)	Continuous Monitoring System (CMS) Requirements.	Must do daily zero and high level calibrations.	No.
§63.8(c)(7)-(8)	Continuous Monitoring Systems Requirements.	Out-of-control periods, including reporting.	Yes.
§63.8(d)	Continuous Monitoring Systems Quality Control.	Requirements for continuous monitoring systems quality control, including calibration, etc.; and must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions.	Yes.
§63.8(e)	Continuous monitoring systems Performance Evaluation.	Notification, performance evaluation test plan, reports.	Yes.
§63.8(f)(1)-(5)	Alternative Monitoring Method.	Procedures for Administrator to approve alternative monitoring.	Yes.
§63.8(f)(6)	Alternative to Relative Accuracy Test.	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system.	No.
§63.8(g)(1)-(4)	Data Reduction	Continuous opacity monitoring system 6-minute averages calculated over at least 36 evenly spaced data points; and continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points.	Yes.
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system.	No.
§63.9(a)	Notification Requirements.	Applicability and State Delegation.	Yes.
§63.9(b)(1)-(5)	Initial Notifications.	Submit notification 120 days after effective date; and Notification of intent to construct/reconstruct; and Notification of commencement of construct/reconstruct; Notification of startup; and Contents of each.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.9(c)	Request for Compliance Extension.	Can request if cannotcomply by date or if installed BACT/LAER.	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Source.	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date.	Yes.
§63.9(e)	Notification of Performance Test.	Notify Administrator 60 days prior.	No.
§63.9(f)	Notification of VE/Opacity Test.	Notify Administrator 30 days prior.	No.
§63.9(g)	Additional Notifications When Using Continuous Monitoring Systems.	Notification of performance evaluation; and notification using continuous opacity monitoring system data; and notification that exceeded criterion for relative accuracy.	Yes.
§63.9(h)(1)-(6)	Notification of Compliance Status.	Contents; and due 60 days after end of performance test or other compliance demonstration, and when to submit to Federal vs. State authority.	Yes.
§63.9(i)	Adjustment of Submittal Deadlines.	Procedures for Administrator to approve change in when notifications must be submitted.	Yes.
§63.9(j)	Change in Previous Information.	Must submit within 15 days after the change.	Yes.
§63.10(a)	Recordkeeping/Reporting.	Applies to all, unless compliance extension; and when to submit to Federal vs. State authority; and procedures for owners of more than 1 source.	Yes.
§63.10(b)(1)	Recordkeeping/Reporting.	General Requirements; and keep all records readily available and keep for 5 years.	Yes.
§63.10(b)(2)(i)-(v)	Records related to Startup, Shutdown, and Malfunction.	Occurrence of each of operation (process, equipment); and occurrence of each malfunction of air pollution equipment; and maintenance of air pollution control equipment; and actions during startup, shutdown, and malfunction.	Yes.
§63.10(b)(2)(vi) and (x-xi)	Continuous monitoring systems Records.	Malfunctions, inoperative, out-of-control; and calibration checks; and adjustments, maintenance.	Yes.
§63.10(b)(2)(vii)-(ix)	Records.	Measurements to demonstrate compliance with emission limitations; and performance test, performance evaluation, and visible emission observation results; and measurements to determine conditions of performance tests and performance evaluations.	Yes.
§63.10(b)(2)(xii)	Records	Records when under waiver.	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test.	No.
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status.	Yes.
§63.10(b)(3)	Records	Applicability Determinations.	Yes.
§63.10(c)(1),(5)-(8),(10)-(15).	Records	Additional Records for continuous monitoring systems.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.10(c)(7)-(8)	Records	Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems.	No.
§63.10(d)(1)	General Reporting Requirements.	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results.	When to submit to Federal or State authority.	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations.	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§63.10(d)(5)	Startup, Shutdown, and Malfunction Reports.	Contents and submission	Yes.
§63.10(e)(1)(2)	Additional continuous monitoring systems Reports.	Must report results for each CEM on a unit; and written copy of performance evaluation; and 3 copies of continuous opacity monitoring system performance evaluation.	Yes.
§63.10(e)(3)	Reports	Excess Emission Reports	No.
§63.10(e)(3)(i-iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations).	No.
§63.10(e)(3)(iv-v)	Excess Emissions Reports.	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations); and provision to request semiannual reporting after compliance for one year; and submit report by 30th day following end of quarter or calendar half; and if there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations.	No.
§63.10(e)(3)(iv-v)	Excess Emissions Reports.	Must submit report containing all of the information in §63.10(c)(5-13), §63.8(c)(7-8).	No.
§63.10(e)(3)(vi-viii)	Excess Emissions Report and Summary Report.	Requirements for reporting excess emissions for continuous monitoring systems (now called deviations); Requires all of the information in §63.10(c)(5-13), §63.8(c)(7-8).	No.
§63.10(e)(4)	Reporting continuous opacity monitoring system data.	Must submit continuous opacity monitoring system data with performance test data.	Yes.
§63.10(f)	Waiver for Recordkeeping/Reporting.	Procedures for Administrator to waive.	Yes.
§63.11	Flares	Requirements for flares	No.
§63.12	Delegation	State authority to enforce standards.	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent.	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference.	Yes.

Table 10 to Subpart DDDDD of Part 63 – Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.15	**Availability of Information.**	**Public and confidential Information.**	**Yes.**

E.1.4 One Time Deadlines Relating to Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD]

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

Requirement	Rule Cite	Affected Facility	Deadline
Initial Notification	**40 CFR 63.7545(b) and 40 CFR 63.9(b)**	**B4**	**Submit initial notification not later than 15 days after the actual date of startup of the affected source.**

Change No. 7:

New applicable requirements for 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units for Boiler B4 have been added to Section E.2 as follows:

SECTION E.2 FACILITY OPERATION CONDITIONS

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

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

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the 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.2.2 PSD Minor Limit [326 IAC 2-2]

The input of No. 6 fuel oil to Boiler B4 shall be limited to less than 1,000 thousand 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.

Compliance with this limit makes 326 IAC 2-2 (Prevention of Significant Deterioration) not applicable.

E.2.3 General Provisions Relating to NSPS [326 IAC 12-1][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 Dc.

E.2.4 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 (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 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 fule 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.2.5 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.2.6 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition E.2.1 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.2.7 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.2.8 Record Keeping Requirements

(a) To document compliance with Conditions E.2.1 and E.2.2, 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.2.7, 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.2.9 Reporting Requirements

A quarterly summary of the information to document compliance with Condition E.2.2 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).

Change No. 8:

New applicable requirements for 40 CFR Part 60, Subpart Kb — 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 for storage tank 175 have been added to Section E.3 as follows:

SECTION E.3 FACILITY OPERATION CONDITIONS

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

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.)

E.3.1 General Provisions Relating to NSPS [326 IAC 12-1][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.3.2 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 m3 but less than 151 m3 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).

Change No. 9:

New applicable requirements for 40 CFR Part 60, Subpart J — Standards of Performance for Petroleum Refineries for Boiler B4 has been added to Section E.4 as follows:

SECTION E.4 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-8-4(10)]: **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 Petroleum Refineries [40 CFR Part 60, Subpart J], the no.4 boiler, 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.)**

E.4.1 General Provisions Relating to NSPS [326 IAC 12-1][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.4.2 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).

Change No. 10:

Quarterly report form for No. 6 fuel oil usage for boilers has been as follows:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name:	Countrymark Cooperative, LLP
Source Address:	1200 Refinery Road, Mount Vernon, Indiana 47620
Mailing Address:	1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.:	T129-7882-00003
Facility:	Boilers B1, B2, ~~and~~ B3**, and B4**
Parameter:	No. 6 Fuel Oil Usage
Limit:	The input of No. 6 fuel oil to the three boilers B1, B2, ~~and~~ 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.

Change No. 11:

Quarterly report form for No. 6 fuel oil usage for boiler B4 has been as follows:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name:	**Countrymark Cooperative, LLP**
Source Address:	**1200 Refinery Road, Mount Vernon, Indiana 47620**
Mailing Address:	**1200 Refinery Road, Mount Vernon, Indiana 47620**
Part 70 Permit No.:	**T129-7882-00003**
Facility:	**Boiler B4**
Parameter:	**No. 6 Fuel Oil Usage**
Limit:	**The input of No. 6 fuel oil to the B4, based on a maximum fuel oil sulfur content of 0.5 percent shall be limited, to 1,000 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.

Conclusion and Recommendation

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 129-22917-00003 and Significant Permit Modification No.: 129- 23090-00003. The staff recommends to the Commissioner that this Part 70 Significant Source and Significant Permit Modification be approved.

Appendix A: Emission Calculations
Boiler Emission

Company Name: Countrymark Cooperative, LLP
Address City IN Zip: 1200 Refinery Road, Mount Vernon, Indiana 47620
Operating Permit No.: 129-22917-00003
Reviewer: Surya Ramaswamy/EVP
Date: 16-May-06

Maximum Steam Pro	70,000	lb/hr
Maximum Water Fee	70,000	lb/hr
Btu required to conve	970	Btu/lb steam
Boiler Efficiency	80.00%	%

Maximum Re = 70000 lb/hr x 970 Btu/lb of steam x 1.0 lb steam input/0.8 lb steam output

= 84875000 Btu/hr
= 84.875 mmBTU/hr

No.6 Fuel Oil:

No.6 Fuel oil is limited 3,214,290 gallons per twelve consecutive months and 0.5% Sulfur content based on NSPS (Subpart Dc).

Maximum Fu = 1,000,000 Gallons/yr
= 115.34 Gallons/hr
= 0.115 1000 Gallons/hr

Natural Gas:

Heat Content = 1020 Btu/cu.ft
Fuel Feed Ra = 83210.78 cu.ft/hr
= 0.083 mmcu.ft/hr

Refinery Fuel Gas:

Heat Content = 1000 Btu/cu.ft
Fuel Feed Ra = 84875.00 cu.ft/hr
= 0.085 mmcu.ft/hr

No.6 Fuel Oil Combustion

Pollutant	Maximum rate, thousand gal/hr	Emission Factor, lb/1000gallons	Emission Rate, lb/hr	Maximum Uncontrolled Emissions,	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	0.115	9.6	1.1073	4.850	0	4.850
PM10	0.115	9.07	1.0461	4.582	0	4.582
SO_2	0.115	157 x %S	9.0542	39.657	0	39.657
NOx	0.115	55	6.3437	27.785	0	27.785
VOC	0.115	0.28	0.0323	0.141	0	0.141
CO	0.115	5	0.5767	2.526	0	2.526
Lead	0.115	0.0005	0.0001	0.000	0	0.000
Benzene	0.115	0.0021	0.0002	0.001	0	0.001
Formaldehy	0.115	0.075	0.0087	0.038	0	0.038
Hexane	0.115	1.8	0.2076	0.909	0	0.909
Naphthalen	0.115	0.00061	0.0001	0.000	0	0.000
Toluene	0.115	0.0034	0.0004	0.002	0	0.002

Emission Factor Source - AP42 Section 1.3, 9/98

Refinery Fuel Gas Combustion

Sulfur Content of Boiler Refinery Fuel Gas - 0.03% (Subject to NSPS Subpart J limit of 0.01 gr/dscf)

Pollutant	Maximum rate, mmcf/hr	Emission Factor, lb/mmcf	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	0.085	7.6	0.6451	2.825	0	2.825
PM10	0.085	7.6	0.6451	2.825	0	2.825
SO_2	0.085	950 x %S	2.4189	10.595	0	10.595
NOx	0.085	50	4.2438	18.588	0	18.588
VOC	0.085	5.5	0.4668	2.045	0	2.045

CO	0.085	84	7.1295	31.227	0	31.227
Lead	0.085	0.0005	0.0000	0.000	0	0.000
Benzene	0.085	0.0021	0.0002	0.001	0	0.001
Formaldehy	0.085	0.075	0.0064	0.028	0	0.028
Hexane	0.085	1.8	0.1528	0.669	0	0.669
Naphthalen	0.085	0.00061	0.0001	0.000	0	0.000
Toluene	0.085	0.0034	0.0003	0.001	0	0.001

Emission Factor Source - AP-42 Section 1.4-7 Natural Gas Combustion, except SO_2 EPA 450/4-90-003. Refinery

Natural Gas Combustion (Back-up Fuel)

Pollutant	Maximum rate, mmcf/hr	Emission Factor, lb/mmcf	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	0.083	7.6	0.6324	2.770	0	2.770
PM10	0.083	7.6	0.6324	2.770	0	2.770
SO_2	0.083	0.6	0.0499	0.219	0	0.219
NOx	0.083	50	4.1605	18.223	0	18.223
VOC	0.083	5.5	0.4577	2.005	0	2.005
CO	0.083	84	6.9897	30.615	0	30.615
Lead	0.083	0.0005	0.0000	0.000	0	0.000
Benzene	0.083	0.0021	0.0002	0.001	0	0.001
Formaldehy	0.083	0.075	0.0062	0.027	0	0.027
Hexane	0.083	1.8	0.1498	0.656	0	0.656
Naphthalen	0.083	0.00061	0.0001	0.000	0	0.000
Toluene	0.083	0.0034	0.0003	0.001	0	0.001

Emission Factor Source - AP-42 Section 1.4-7 Natural Gas Combustion.

Worst Case Boiler Summary

Pollutant	Emission Rate, lb/hr	Maximum Uncontrolled Emissions, ton/yr	Pollution Control Efficiency, %	Maximum Controlled Emissions, ton/yr
PM	3.5591	15.589	0	4.850
PM10	3.3626	14.728	0	4.582
SO_2	46.5646	203.953	0	39.657
NOx	20.3905	89.311	0	27.785
VOC	0.4668	2.045	0	2.045
CO	7.1295	31.227	0	31.227
Lead	0.0002	0.001	0	0.000
Benzene	0.0008	0.003	0	0.001
Formaldehy	0.0278	0.122	0	0.038
Hexane	0.6673	2.923	0	0.909
Naphthalen	0.0002	0.001	0	0.000
Toluene	0.0013	0.006	0	0.002

Appendix A: Emissions Calculations
Main Refinery Flare

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Indiana 47620**
Operating Permit No.: **129-22917-00003**
Reviewer: **Surya Ramaswamy/EVP**
Date: **16-May-06**

Main Refinery Flare, burning process gas, identified as RCD-1, installed in 1945 and replaced in 2006 and exhausting to stack 118

Heat Input	Potential Throughput	Pollutant	PM*	PM10*	SO2	NOx	VOC	CO
MMBtu/hr	MMCF/yr	Emission Factor in lb/MMCF	7.6	7.6	3429.7	22.2	5.5	84.0
14.0	122.6	Potential Emission in tons/yr	0.47	0.47	210.31	1.36	0.34	5.15
		HAPs - Organics	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
		Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
		Potential Emission in tons/yr	0.00	0.00	0.00	0.11	0.00	
		HAPs - Metals	Lead	Cadmium	Chromium	Manganese	Nickel	
		Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
		Potential Emission in tons/yr	0.00	0.00	0.00	0.00	0.00	

Methodology

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu
Source of Emission Factors:
Process gas: PM, PM-10, NOx, VOC, CO from AP-42, Chapter 1.4, (3/98)
SO2 from AIRS 3-06-001-06 (950 x % S)
No. 6 fuel oil: All pollutants' emission factors from AP-42, Chapter 1.3, (9/98)

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emission Calculations
Tank VOC Emissions - Maximum PTE

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Indiana 47620**
Operating Permit No.: **129-22917-00003**
Reviewer: **Surya Ramaswamy/EVP**
Date: **16-May-06**

Tank Number	Product Stored	Total VOC Tons/yr
22B	Residual Fuel Oil No.6	0.59
173	Residual Fuel Oil No.6	0.59
174	Residual Fuel Oil No.6	0.59
175	Gasoline (RVP 13)	5.15
Total		6.92

Note: Storage tank emissions are estimated using USEPA's Tanks 4.09 software program and provided by the source.

Tank	Product	VOC	HAP Emissions (TPY)					Total
Number	Stored	Emissions Tons/yr	Benzene	Toluene	Ethyl-Benzene	Xylenes	n-Hexane	
22B	Residual Fuel Oil No.6	0.59	0.02	0.04	0.00	0.02	0.03	0.09
173	Residual Fuel Oil No.6	0.59	0.02	0.04	0.00	0.02	0.03	0.09
174	Residual Fuel Oil No.6	0.59	0.02	0.04	0.00	0.02	0.03	0.09
175	Gasoline (RVP 13)	5.15	0.02	0.03	0.00	0.01	0.04	0.09
Total		6.92	0.06	0.132	0.005	0.059	0.111	0.37

Note: Storage tank emissions are estimated using USEPA's Tanks 4.09 software program and provided by the source.

Appendix A: Emissions Calculations
Tank 35, 40, and 46 (APTA Test)

Company Name: **Countrymark Cooperative, LLP**
Address City IN Zip: **1200 Refinery Road, Mount Vernon, Indiana 47620**
Operating Permit No.: **129-22917-00003**
Reviewer: **Surya Ramaswamy/EVP**
Date: **16-May-06**

	Tank 35	Tank 40	Tank 46	Total
2004 (VOC in tpy)	3.025	0	5.139	8.164
2005 (VOC in tpy)	3.037	0.015	5.247	8.299
Average (VOC in tpy)	3.031	0.0075	5.193	8.2315
Projected (VOC in tpy)	0.165	5.965	1.391	7.521
Net Change (VOC in tpy)	-2.866	5.9575	-3.802	-0.7105

Note:
There is a decrease in VOC emissions in Tank 35 and 46 due to change in service from gasoline to distillate, and an increase in VOC emissions in Tank 40 due to change in service from distillate to gasoline.

What if you are not satisfied with this decision and you want to file an appeal?

Who may file an appeal?
The decision described in the accompanying Notice of Decision may be administratively appealed. Filing an appeal is formally known as filing a "Petition for Administrative Review" to request an "administrative hearing."

If you object to this decision issued by the Indiana Department of Environmental Management (IDEM) and are: 1) the person to whom the decision was directed, 2) a party specified by law as being eligible to appeal, or 3) aggrieved or adversely affected by the decision, you are entitled to file an appeal. (An aggrieved or adversely affected person is one who would be considered by the court to be negatively impacted by the decision. If you file an appeal because you feel that you are aggrieved, it will be up to you to demonstrate in your appeal how you are directly impacted in a negative way by the decision).

The Indiana Office of Environmental Adjudication (OEA) was established by state law – see Indiana Code (IC) 4-21.5-7 – and is a separate state agency independent of IDEM. The jurisdiction of the OEA is limited to the review of environmental pollution concerns or any alleged technical or legal deficiencies associated with the IDEM decision making process. Once your request has been received by OEA, your appeal may be considered by an Environmental Law Judge.

What is required of persons filing an appeal?
Filing an appeal is a legal proceeding, so it is suggested that you consult with an attorney. Your request for an appeal must include your name and address and identify your interest in the decision (Or, if you are representing someone else, his or her name and address and their interest in the decision). In addition, please include a photocopy of the accompanying Notice of Decision or list the permit number and name of the applicant, or responsible party, in your letter.

Before a hearing is granted, you must identify the reason for the appeal request and the issues proposed for consideration at the hearing. You also must identify the permit terms and conditions that, in your judgment, would appropriately satisfy the requirements of law with respect to the IDEM decision being appealed. That is, you must suggest an alternative to the language in the permit (or other order, or decision) being appealed, and your suggested changes must be consistent with all applicable laws (See Indiana Code 13-15-6-2) and rules (See Title 315 of the Indiana Administrative Code, or 315 IAC).

The effective date of this agency action is stated on the accompanying Notice of Decision (or other IDEM decision notice). If you file a "Petition for Administrative Review" (appeal), you may wish to specifically request that the action be "stayed" (temporarily halted) because most appeals do not allow for an automatic "stay." If, after an evidentiary hearing, a "stay" is granted, the IDEM-approved action may be halted altogether, or only allowed to continue in part, until a final decision has been made regarding the appeal. However, if the action is not "stayed" the IDEM-approved activity will be allowed to continue during the appeal process.

(See reverse side)

Where can you file an appeal?
If you wish to file an appeal, you must do so in writing. There are no standard forms to fill out and submit, so you must state your case in a letter (called a petition for administrative review) to the Indiana Office of Environmental Adjudication (OEA). Do not send the original copy of your appeal request to IDEM. Instead, send or deliver your letter to:

The Indiana Office of Environmental Adjudication
100 North Senate Ave.
Indiana Government Center North
Room 1049
Indianapolis, IN 46204

If you file an appeal, also please send a copy of your appeal letter to the IDEM contact person identified in the Notice of Decision, and to the applicant (person receiving an IDEM permit, or other approval).

Your appeal (petition for administrative review) must be received by the Office of Environmental Adjudication in a timely manner. Different types of permit approvals have different deadlines for filing an appeal. The accompanying Notice of Decision (NOD) explains how to determine the due date for filing an appeal for this particular permit decision. To ensure that you meet this filing requirement, your appeal request must be:

1) Delivered in person to the OEA by the close-of-business on the due date. (If the due date falls on a day when the Office of Environmental Adjudication (OEA) is closed for the weekend or for a state holiday, then your petition will be accepted on the next business day on which OEA is open.); or
2) Given to a private carrier who will deliver it to the OEA on your behalf, (and from whom you must obtain a receipt dated on or before the due date); or
3) For those appeal requests sent by U.S. Mail, your letter must be postmarked by no later than midnight of the due date; or
4) Faxed to the OEA at 317/233-9372 before the close-of-business of the due date, provided that the original signed "Petition for Administrative Review" is also sent, or delivered, to the OEA in a timely manner.

What are the costs associated with filing an appeal?
The OEA does not charge a fee for filing documents for an administrative review or for the use of its hearing facilities. However, OEA does charge a fifteen cent ($.15) per page fee for copies of any documents you may request. Another cost that could be associated with your appeal would be for attorney's fees. Although you have the option to act as your own attorney, the administrative review and associated hearing are complex legal proceedings; therefore, you should consider whether your interests would be better represented by an experienced attorney.

What can you expect from the Office of Environmental Adjudication (OEA) after you file for an appeal?
The OEA will provide you with notice of any prehearing conferences, preliminary hearings, hearings, "stays," or orders disposing of the review of this decision. In addition, you may contact the OEA by phone at 317/232-8591 with any scheduling questions. However, technical questions should be directed to IDEM at the number indicated on the Notice of Decision.

Do not expect to discuss details of your case with the OEA other than in a formal setting such as a prehearing conference, a formal hearing, or a settlement conference. The OEA is not allowed to discuss a case without all sides being present. All parties to the proceeding are expected to appear at the initial prehearing conference.